ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

APRIL 1993

IMPERIAL OIL LIMITED

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MEMORANDUM

ENVIRONMENT
HEALTH & SAFETY DEPT.
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Imperial Oil
Chemicals Division

Be an
Effective
Safety
Team

Safety, Health & Environment

August 12, 1993

RE: EMISSION ESTIMATING MANUALS

TO: J.T. Badiani, Dave Beer, Ted Hsiung, Dave Matthews, Chris Micek, Jim Rogers, Rudy Sandau

FROM: Idrees Mahmud

Attached are the copies of "Environmental Release Inventory Guidelines" and "Emission Estimating Guidebook."

The Environmental Release Inventory Guideline was created to respond to Environment Canada's requirement to compile a National Pollutant Release Inventory (NPRI). The Guideline provides a common approach within IOL to track and report on releases associated with IOL operations. Please note that the Section 090 of the Guideline will be developed by each product line as it is site/product line specific.

Detailed explanations of methods to estimate releases from various sources can be found in "Exxon Research & Engineering, Emission Estimating Guidebook." This draft version, prepared under the Code 500 Engineering Technology Research & Development Program, contains sections on Fugitive, Tanks, Secondary, Transfer Operations and Combustion.

Imperial Oil has not selected any Environmental Data Management System yet and continues to evaluate Oracle's EIS system.

If you require any additional information, please call me at (519) 339-2531.

Attach.
/cam
cc: D. Bandy
E. Bristow (w/o attach.)
J. Trainor (w/o attach.)
G. Tremblay (w/o attach.)
M. Preudhomme (w/o attach.)

IM\Emimnl.del

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: INTRODUCTION

SUBJECT: NOTICE

DESIGN

This document has been designed by an Imperial Oil Limited project team to provide guidance and information. It is for the sole-use of Imperial Oil Limited sites that are carrying out a release inventory as required under Section 16 of the Canadian Environmental Protection Act - National Pollutant Release Inventory program.

It is provided with the understanding that contents reflect the project team's best judgement in light of the information available at the time of preparation.

This manual should be updated on a regular basis to incorporate experience, and the changing business and regulatory needs.

If specific advice or assistance (not covered in this manual) is required, please contact your site or divisional environmental professional.

PROPRIETARY NOTICE

This manual has been produced by Imperial Oil Limited. Its contents are **PROPRIETARY.** It may not be produced, reproduced, or published in whole or part, nor be shown to anyone outside of Imperial Oil Limited without written authorization from the Director, Environment and Safety Department.

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IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

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IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: **RELEASE INVENTORY BASIS & MANAGEMENT**

SUBJECT: **INTRODUCTION**

BACKGROUND

This Environmental Release Inventory Guideline was created to respond to Environment Canada's initiative under authority of Section 16 of the Canadian Environmental Protection Act to compile a National Pollutant Release Inventory (NPRI). The Guideline provides a common approach within all Imperial Oil Limited (IOL) sites to track and report on releases associated with IOL operations.

Release inventories are a valuable source of information and can be used as the basis for on-going release management, regulatory and community response and for setting priorities for pollution reduction programs.

There are two basic steps in compiling a release inventory. First, the list of reportable substances must be defined for a site. Second, the amount of that substance released and transferred to the environment (air, water, land) must be calculated, measured or estimated.

Details on the purpose of the project initiating this Guideline can be found in the project's Definition Document (Appendix A). Parts of the Background section are included in section 020-020.

PURPOSE

The Guideline is a reference standard for implementation for IOL facilities in the appropriate methodologies and effective approaches to identifying reportable substances and calculating the releases/transfers to the environment. It will serve to consolidate information in a standard approach across IOL, while supporting defensible release inventories. The Guideline will also serve as a resource document for training/updating inventory team members.

It should be noted that most of the NPRI details for 1993 have been published by Environment Canada. However, future changes can and should be expected.

CLIENT

The clients of this Guideline are all the Imperial Oil sites that are required to compile a National Pollutant Release Inventory.

LAYOUT

The Guideline can generally be divided into two parts:

Part A
Part A contains the generic (applicable to all IOL sites) Sections 020 through 060:

- Release Inventory Basis and Management
- Identifying Reportable Substances
- Release Inventory Methodology and Data Requirements
- Emission Estimating Guide, and
- Information Management System.

Part B
Part B, Sections 070 through 090, will provide information specific to IOL Divisions. These are the Release Inventory Guides ("How To" Sections) for:

- Resources Division
- Products Division, and
- Chemicals Division.

The appendices contain the 1993 NPRI substance list; lists of high profile substances; etc.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY BASIS & MANAGEMENT

SUBJECT: BACKGROUND - DEFINITION DOCUMENT

PURPOSE

In October, 1992, Imperial Oil's Environmental Health and Safety committee sponsored a project to define and design a synergistic approach to compiling release inventories that meet business needs in an effective and timely manner.

A project team was assembled composed of representatives from the Products, Chemicals and Resources Divisions as well as representatives of the management company. The team's mandate was to "deliver a management system that tracks and measures IOL's releases to the environment to meet business needs". IOL Divisions were the clients of this work.

This document:

- described the products of the definition phase of the project and provided a basis for approvals for developing tools, acquiring information systems and implementing the pollutant inventory across IOL.
- provided a game plan for the project team, and
- met corporate standards for project documentation.

DRIVING FORCES

The pollutant inventory will meet policy, regulatory and business needs.

POLICY

Elements of Imperial's policies and environmental strategic framework require that "environmental hazards associated with company activities are identified, assessed and managed".

Similarly, an element of the Operations Integrity Management Framework is described as "A system is in place to identify hazards, assess consequences and probabilities, and evaluate prevention and mitigation measures for the ongoing management of risk".

The pollutant inventory will consolidate information on releases of hazardous substances, as well as conventional pollutants.

REGULATORY

Environment Canada will be compiling a National Pollutant Release Inventory (NPRI). Each year, under authority of Section 16 of the Canadian Environmental Protection Act, it will request, any facility with 10 or more employees to submit a report for each substance on the NPRI list manufactured (including as a byproduct), produced or otherwise used in excess of 10,000 kg per year. The report will include releases to all media (air, water, soil, underground). 1993 releases are to be reported in early 1994.

The data from the NPRI will be used by other federal programs such as the Accelerated Reduction or Elimination of Toxics (ARET), Pollution Prevention and the initiatives to address ground level ozone.

BUSINESS

Under their Responsible Care commitment, all Canadian Chemical Producers Association member companies are required to participate in a National Emissions Reduction Master plan (NERM). The first step of the plan is to develop multimedia emissions inventories. The federal NPRI program design was based on NERM and the US Toxic Release Inventory (TRI).

Chemicals Division is also required to contribute to the Exxon Chemical Emission and Waste Reduction Program.

The inventory data will be used by Imperial facilities to:

- better understand hazardous releases from their sites, so that they may be assessed and managed appropriately, considering the national context.
- establish a base case against which to measure progress
- improve discussions with regulatory agencies
- improve community relations and public image.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY BASIS & MANAGEMENT

SUBJECT: BACKGROUND - DEFINITION DOCUMENT

CORPORATE APPROACH

PURPOSE

A common corporate approach is being taken to the definition and design phases. This will:

- reduce the operational impacts and costs for response to regulatory (e.g. NPRI), industry (e.g. NERM) and corporate (e.g. OIMS) pollutant management initiatives by minimizing redundant initial and ongoing effort between and within Imperial divisions.
- capture the benefits and synergy of bringing broad business/technical perspectives together to define requirements and identify solutions while maintaining enough flexibility to accommodate divisional differences.
- improve the quality and consistency of internal/external pollutant reporting and communications by applying consistent assumptions, definitions, methods and information systems tools throughout the company.

DRIVING FORCES

The driving forces for developing a common corporate approach include:

- management expectations that IOL divisions will cooperate on "macro processes" within the company to minimize duplication of systems and costs (C.I. Council).
- resource constraints within all operations for this non-discretionary activity and severe time constraints associated with NPRI reporting.
- requirements for every division to document hazardous emissions for government audits.
- consistent external IOL communications will minimize liabilities, community concerns and potential impacts on the company's public image and profitability.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: **RELEASE INVENTORY BASIS & MANAGEMENT**

SUBJECT: **ADMINISTRATION**

RESPONSIBILITY FOR RELEASE INVENTORIES

Management of releases, including compilation of the release inventory and projection of forecast releases, is the responsibility of site or geographical area management. Within the Resources Division, releases are managed at the geographic regional level; within Products and Chemicals Divisions, the site manager is the individual identified as the responsible person.

INVENTORY AND FORECAST APPROVALS

Inventories and forecasts of release information are collated at the operating division level. Submissions of release information will receive prior review and approval by operating division management. The 1993 release inventories and forecasts will require review with the IOL Management Committee prior to submission.

CORPORATE COORDINATION

The Imperial Oil Environment and Safety department (ESD) is responsible for providing overall coordination in the compilation of the release inventories and provides a consulting role in the development of division forecasts and strategies. Any requirement to prepare an overall IOL release inventory will also be coordinated by ESD.

METHODOLOGY

The methodologies contained in this manual will be applied by the operating divisions to achieve consistency and quality of the information.

This manual will be updated to reflect the standard IOL methodologies. The details of those methodologies are outlined in the Exxon Research & Engineering, Emission Estimating Guidebook.

Imperial's representative to Exxon's Code 500 Program is responsible for ensuring that the IOL network is notified of methodology changes and that the Exxon Guide meets IOL needs.

TIMING	Divisional release inventories will be completed by the end of April each year in order to enable compilation of the data for stewardship reviews, confirmation of the business strategies and development of any required communication plan.
ENVIRONMENTAL RELEASE INVENTORY GUIDELINE	Responsibility for maintaining the Imperial Oil Limited - Environmental Release Inventory Guideline is with ESD, who will act as the coordinator for any necessary updates, on behalf of the operating divisions. The divisions themselves are responsible for those sections which identify their individual "approaches". (Sections 070, 080, 090).
INVENTORY FORMAT	Operating divisions will submit their release information in the format required by NPRI. Electronic transfer of the release information will be used in order to facilitate collation of the data at the division and company level.
VERIFICATION	Each site should keep a copy of the complete inventory report generated for each year. In addition, supporting information and/or documents gathered during the inventory process should be documented and maintained by the facility. Documents could include purchasing and inventory records, monitoring data, engineering calculations, estimation methods, emission factors, reference materials, etc., ...as well as the submission to Environment Canada. The facility, or their representative, must be able to recreate the submission from base data.
INFORMATION SYSTEM	An environmental information system will be made available to the operating divisions, sites and geographic areas to assist in the collection and submission of the release inventories in a consistent manner. The environmental information system will be administered by the Occupational Health Division on behalf of the operating divisions and ESD. Information Services Department will provide systems support.

COMMUNICATIONS

Each major site, geographic area or division is responsible for developing a communication plan which is appropriate for their employees and the communities in which they operate. ESD is responsible for coordinating any required company-wide communications, with the support of the Public Affairs Department.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: **RELEASE INVENTORY BASIS & MANAGEMENT**

SUBJECT: **DEFINITIONS, TRIGGERS & EXEMPTIONS**

INTRODUCTION	This section contains definitions, triggers and exemptions that are applicable to NPRI and IOL release inventories.
ARTICLE EXEMPTION	A closed item containing a listed substance (e.g.: mercury in a thermometer) that does not release the substance during normal use is considered an article if the facility uses the item as intended and listed substances are not released. Articles are not included in any NPRI calculations.
CAS NUMBER	The Chemical Abstract Service Number. This number is assigned to a chemical listed with the Chemical Abstract Service, a systematic computerized chemical information source developed by the CAS Division of the American Chemical Society. This database has become the repository of all significant chemical research information reported in the international literature. An extensive in-depth systems approach to the storage and handling of chemical information.
CONCENTRATION	The relative fraction of one substance in another, for NPRI purposes expressed in weight percent.
EFFLUENT	Releases in water.
EMISSION FACTOR	The relationship between the amount released and the amount of raw material processed. For example, the fugitive emission (AP-42) factor for a valve in light liquid service is 0.011 kg/hr/source.
EMISSIONS	Releases to air.
FACILITY	All buildings, equipment, structures and other stationary items which are located on a single site or on contiguous or adjacent sites and which are owned or operated by the same person. Contiguous operations owned by the same corporation may be considered a single facility.

FACILITY EXEMPTIONS

- The distribution or retail sale of fuels.
- Transportation Fuel Combustion
- Oil and Gas Wells
- Research on or testing of substances.
- Maintenance and repair of transportation vehicles.

FUGITIVE EMISSIONS

Releases to air from dispersed sources (ponds, seal leaks) rather than point sources (stacks and vents).

FUMES AND DUST

When the processing or otherwise use of an item generates fumes, dust, fillings, or grindings, the quantity of that item must be counted for reporting and the fumes, dust, fillings and grindings reported as releases or wastes. If wastes incorporating filings and grindings are recycled off-site, they have to be reported as a transfer. If they are recycled on-site, they do not have to be reported. In addition, scrap pieces that are recognizable as an article do not constitute a release.

GROSS/NET RELEASES OF OPERATED SITES

The site should be aware of the difference between "gross" and "net" emissions when generating release inventories. The "net" release for a site takes into account (subtracts) the amount of substance that enters from off-site. For example, releases discharged via cooling water would take into account the substances already in the cooling water as it entered the site. In order to report "net" releases, facilities must have a valid basis for the quality of the inlet stream.

HAZARDOUS WASTE

A waste, or combination of wastes, which because of its quantity, concentration, toxicity, corrosivity, mutagenicity, flammability, physical, chemical, or infectious characteristics may:

1. Cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or

2. Pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of, or otherwise managed.

IMPORT

Is defined as causing a substance to be imported into the customs territory of Canada.

INTERMEDIATE STREAMS

Flows of mixtures (streams) in process units, excluding waste, facility feed and product streams. For example, the light cat naphtha stream would be an intermediate stream.

LEAK

Discharge of a substance to the environment, either air, water or land. Please note that a leak and a spill differ in terms of the time required for an event. Leaks occur over periods of days to months; spills normally occur over a period of hours to days.

MANUFACTURE

To produce, prepare, compound or import a substance listed in the NPRI. The term "manufacture" includes the generation of a listed substance as a by-product or impurity.

Certain NPRI substances may be manufactured as a result of wastewater or other treatment processes.

METRIC VS. IMPERIAL

The NPRI submission will be in metric units. Currently, it is intended that the environmental information system will allow the data to be entered in either metric or imperial units.

OFF-SITE FACILITY

A collection of equipment and associated land area which serves to receive waste and process it. The facility may have available one, many or all of a large number of processing methods. (recovery, reuse, recycle, destruction, containment, neutralization).

OTHERWISE USE	The term "otherwise use" encompasses any use of a listed substance at a facility that does not fall under the definitions of "manufacture" or "process".
PROCESS	The term "process" means the preparation of a listed NPRI substance, after its manufacture, for distribution in commerce. Processing includes a preparation of the substance in the same physical state or chemical form as that received by your facility, or a preparation that produces a change in physical state or chemical form. The term also applies to the processing of a mixture or formulation that contains a listed substance as one component.
RECYCLE	As commonly used, means using discarded materials and objects in original or changed form rather than wasting them. Precisely used, refers to re-processing a material into new finished products.
RELEASES	Means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment (air, water or land) of any NPRI substance.
REUSE/RECYCLE OPERATIONS	Threshold determinations of listed substances recycled or reused at a facility are based only on the amount of substance that is added during the year, not on the total volume in the system. Any substances "recycled" off-site and returned to the facility are treated as the equivalent of newly purchased material for purposes of NPRI threshold determinations.
RUN-OFF	Water which, having fallen on the surface of a facility, flows across the surface, picking up materials.
SITE REPORTING TRIGGER	Facilities at which employees worked a total of not less than 20,000 hours during the reporting year. (See Facility Exemptions).

SPILLS	An abnormal, or accidental, discharge into the environment (ie: air, water and land). Spills and leaks differ in terms of the time involved with the event. Spills occur in hours, while leaks occur over a period of days to months.
SUBSTANCE REPORTING TRIGGERS	Releases of any NPRI substance (see Appendix C) manufactured, processed or otherwise used in excess of 10 tonnes (10,000 kg) (>1% concentration in stream) by a facility in the reporting year, must be reported. (See Manufacture, Process, Otherwise Use and Use and Article Exemptions).
TRANSFERS	The quantity of NPRI substances sent off-site other than those contained in products.
USE EXEMPTIONS	Certain uses of listed substances are specifically exempted: ■ Use of a substance as a structural component of a facility (e.g. paint). ■ Use in routine janitorial or facility grounds maintenance. ■ Personal uses by employees or other persons. ■ Use of products containing substances for the purposes of maintaining motor vehicles operated by the facility. ■ Use of substances contained in intake water or intake air, such as water for process cooling, or air used either as compressed air or for combustion.
VOC	Abbreviation for volatile organic compound, excluding methane and ethane.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: **RELEASE INVENTORY BASIS & MANAGEMENT**

SUBJECT: **DATA ANALYSIS/NPRI SUBMISSION**

DATA ANALYSIS

- Quality and defensible release inventories to be generated across IOL to meet regulatory needs.
- Standard methods to be utilized in identifying reportable substances and calculating releases of those substances to all environmental media in order to have corporate consistency and defendable data.
- Conservative estimates to be used unless there is justification for using a lower value (i.e. error on the high side to avoid annual increases due to estimation methods).

NPRI SUBMISSION FORMS

- At this time, the Environment Canada reporting forms for NPRI submission have not been finalized; thus the reporting format has been based upon the NPRI reporting elements listed in Appendix 7 of "A National Pollutant Release Inventory, The Final Report of the Multi-Stakeholder Advisory Committee". (Dec/92). Appendix B.
- The NPRI reporting elements consist of two parts:

Part A - Facility Identification Information

Part B - Substance Specific Release & Transfer Information

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY BASIS & MANAGEMENT

SUBJECT: GUIDING PRINCIPLES

GUIDING PRINCIPLES

1. Focus on NPRI regulatory requirements.

2. Establish a prioritized approach based on the overall inventory. Approach should be logical, sequential and well organized.

3. Use typical and readily available data, unless there is a defendable reason to expend energy and resources to obtain more exacting data. Use conservative case when simplifying.

4. Document extensively for future reference and audit purposes. Good documentation will help ensure continuity and minimize future inventory efforts.

5. Do it right the first time. Increase efficiency by addressing what is really needed and avoid shortcuts that will require repeated annual studies to gain understanding.

6. Perform initial screening pass to determine which substances need to be reported. Concentrate on the largest sources or substances of greatest concern. (See Appendix D). Strive for effectiveness and efficiency of effort. Use the 80/20 rule as resources are limited.

7. The Guideline does not require site-wide sampling and analysis. You may use good engineering judgement to derive the information.

8. Use the following hierarchy when selecting stream composition or other default data:
    1. Site specific data (if available)
    2. Data from IOL/Exxon sites
    3. Data from industry (CPPI, API)
    4. Other

9. It is not imperative to understand all details/mathematics of the calculations to compile a quality inventory. The information management system will serve as a tool to collect and manipulate data. Minimize the number of times data is handled.

10. Make it a point to share key learnings with other IOL sites; and whenever appropriate, use the learnings from other IOL/Exxon sites.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: IDENTIFYING REPORTABLE SUBSTANCES

SUBJECT: OVERVIEW

OVERVIEW

- Identification of reportable substances is the first step in generating a release inventory for a site. It helps define WHAT substances must be reported under NPRI (ie: the site will have to submit a report for each chemical that is identified as a reportable substance).

- Each site must define a list of reportable substances from the NPRI list of 178 chemicals (see Appendix C for complete 1993 NPRI list).

- A facility will likely report on a fraction of the total NPRI list, depending on what is manufactured, processed or used at the site. Reportable substances are those that have been manufactured, processed or otherwise used in excess of 10 tonnes or 10,000 kg during the reporting year. The substance may be in pure form or be in a mixture in excess of 1% by weight.

- Definitions for "manufactured", "processed" and "otherwise used" can be found in section 020-040. Substances stored/stockpiled on site are excluded/not counted until used when assessing if the threshold of 10 tonnes is exceeded.

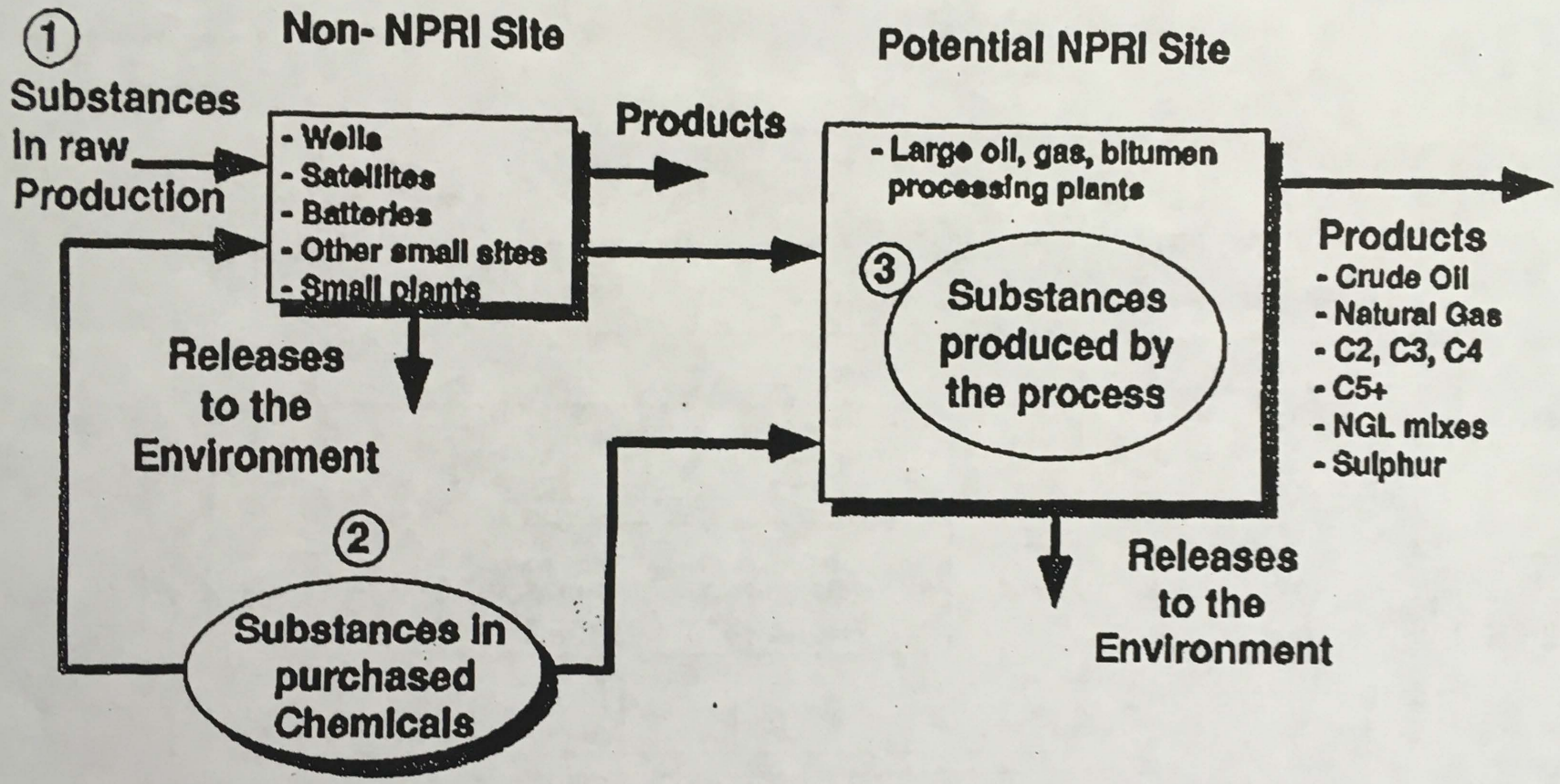
- The following streams are generally considered when defining the list of reportable substances:

  - Facility products (e.g.: gasoline, LPG, PVC).
  - Facility feedstock (e.g.: crude oil, benzene).
  - Intermediate process streams (e.g.: light cat naphtha).
  - Waste streams (e.g.: wastewater treatment plant effluent).
  - Purchased chemicals (e.g.: sulphuric acid).

IDENTIFYING REPORTABLE SUBSTANCES	OVERVIEW

- There may be different approaches to identifying which substances are reportable in each operating division. Section 030-020 outlines an approach to a refinery or chemical plant; while Fig. 1 illustrates a substance source model for Resources Division.

Substance Source Model



○ - Sources of listed substances that could be released to the environment

Resources Division

FIGURE 1

MACRO MATERIAL BALANCE DIAGRAM

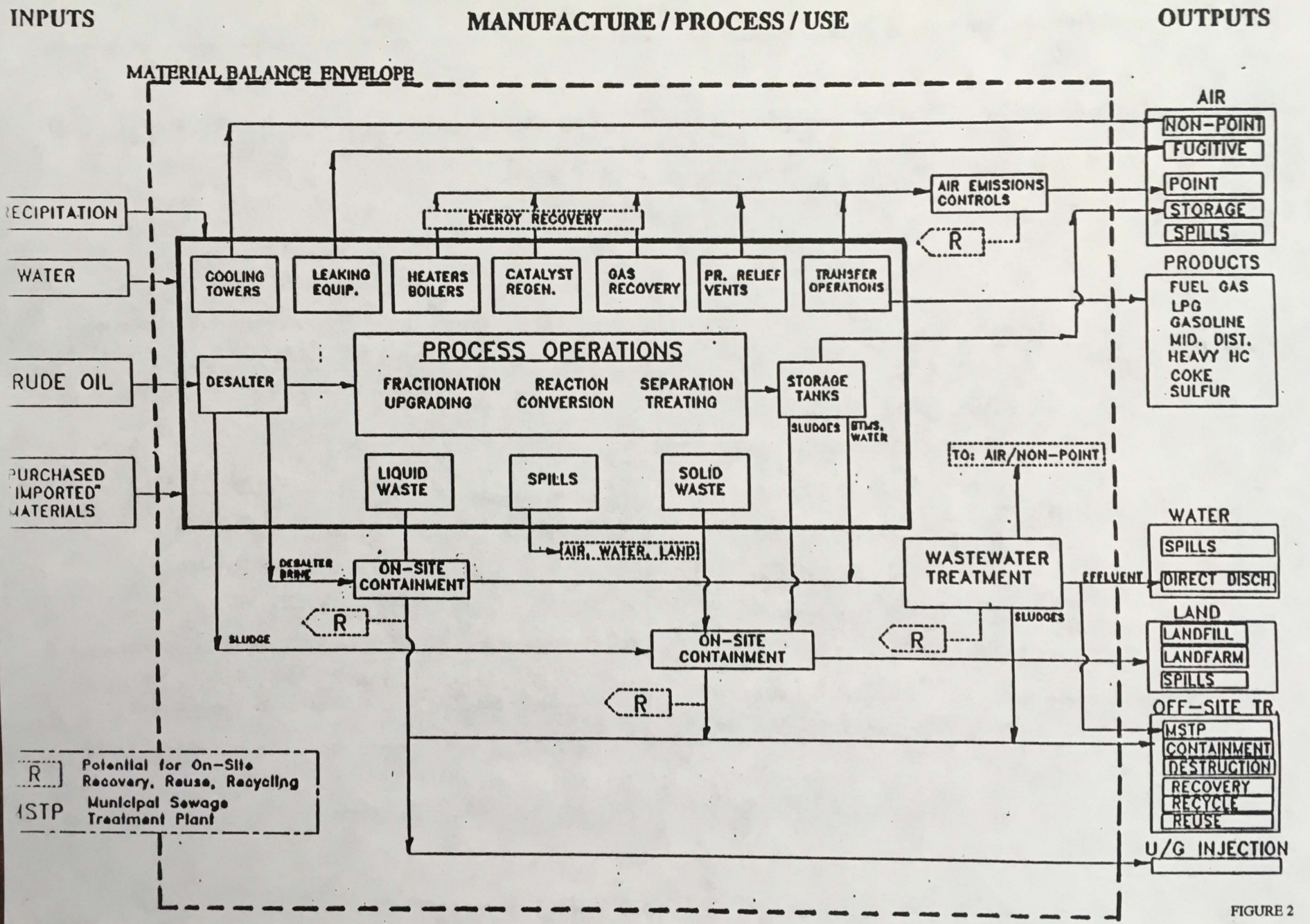


FIGURE 2

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: IDENTIFYING REPORTABLE SUBSTANCES

SUBJECT: QUANTIFYING APPROACHES/SOURCES

IDENTIFICATION APPROACHES/DATA SOURCES

There are two general approaches to the identification of reportable substances, depending on the division of Imperial Oil. The approaches differ because of differences in the manufacturing process in the upstream (Resources) and downstream (Products/Chemicals) end of the business.

Resources processing involves the separation of mixtures of raw production streams; as opposed to the manufacturing or refining of new molecules from various feedstocks (downstream). Therefore the approach of the Resources division in identifying reportable substances will be to examine substances that appear in the feedstock stream; followed by purchased chemicals; followed by the products.

Fig No. 1 depicts an overview of the Substance Source Model for the Resources division.

The Products/Chemicals division approach will be based on the fact that new molecules are created within the process. Thus, the focus will be toward the identification of substances in product streams (such as gasoline, middle distillates, lubes, etc.); followed by feedstock streams (crude oil); followed by intermediate process and waste streams; followed by purchased products.

Fig. No. 2 is a macro material balance diagram for a generic refinery.

Regardless of the divisional approach, there are five general substance sources that should be considered when generating a list of reportable substances:

1. Substances in raw materials/feedstocks (e.g.: crude).

2. Substances in purchased chemicals/catalysts (e.g. methanol, ethylene glycol, chlorine, etc.).

3. Substances in intermediate streams (NB: Sometimes substances can concentrate through the petroleum process to the stage where they must be counted/have an impact).

4. Substances in products produced by process/facility (e.g.: gasoline in downstream; crude oil in upstream, etc.).

5. Substances in by-products (including waste streams).

FACILITIES

The NPRI definition of facility may require contiguous operations owned by the same corporation (e.g. refinery and chemical plant, pumping station) to determine their reportable substances as if they were a single operation.

REFINING APPROACH TO IDENTIFICATION STEP

(See Identification of Reportable Substances - Approach - Fig. No. 3)

The first step to identifying reportable substances is a "gross screening" of the total NPRI substance list. Basically, this step involves the use of a database to identify the chemicals that are on/off the site; and a qualitative review of the generated lists with reportable substance lists from US refineries and other IOL refineries.

What follows are annotations for the individual steps/elements that make up the substance source model for the products division:

START: TOTAL NPRI LIST

Begin with the total NPRI list of chemicals: 178 (see Appendix C).

ETHIS SCAN

The Exposure Tracking and Health Information System (ETHIS) can identify chemicals that have been tracked at a particular site. ETHIS summaries are available for all sites in IOL. For example: Sarnia Refinery is predicted to have 62 substances; Strathcona Refinery is predicted to have 54 substances; etc.

Typical information includes:

- the NPRI substance
- the chemical agent or material
- the user or process unit/area

(Information is also provided on the typical concentration for the NPRI substance in the chemical agent.).

Thus, very quickly, a site can separate the total list of NPRI substances into those:

- in use at site
- not in use at site.

QUALITATIVE REVIEW

EXXON DATABASES

A quick review of the predicted substances in use/not in use at a site can be performed by comparing the site's predicted stream with those streams reported by Exxon refineries and chemical plants under the US Toxic Release Inventory.

Fig No. 4 summarizes the streams reported by some Exxon facilities.

OTHER IOL SITES

Some substances that are in use at a site may not be picked up by ETHIS. Therefore a quick review of the predicted substances for other IOL sites may lead to some additional reportable substances.

NON REPORTABLE LIST

After a qualitative review of the predicted list of substances, the substances that are not in use at the site are placed on a non-reportable list.

The next step in the identification process is a COMMITTEE SCREENING step. The committee would meet to review the confirmed list of substances and to separate the list into three groups: those substances that are obviously in use in excess of 10,000 kg/year; those substances that are obviously in use less than 5,000 kg/year; and those substances which usage cannot be established or are known to be in the range of 5,000 to 10,000 kg/year. It is not the expectation of the committee to do any quantification calculations, but to use their knowledge and experience to further segregate the list of substances in use at the site.

SCREENING COMMITTEE

It is envisioned that the listed substances in use at a site will undergo a review by a committee of knowledgeable persons. A typical committee might consist of the site's head chemist; process contacts; purchasing or inventory person; site information management person; site industrial hygienist; environmental contact; etc.

REVIEW OF STANDARDS

The committee must be familiar with the corporation's and the government's rules and definitions involved with identifying reportable substances.

REVIEW OF SITE INFORMATION SYSTEMS

Someone on the committee (preferably the information management person) should have reviewed the site's computerized systems to know the extent of information available through the site's computerized systems. For example, the RMS (Refinery Maintenance System) or the PPMS (Plant Performance Monitoring System) may contain valuable information that will quickly help to categorize some of the substances in use at the site.

REVIEW DATA SOURCES

Other sources of data include: Environmental Monitoring Reports, Material Safety Data Sheets, Site Chemical Review Committees, Lab Reports, Purchasing Records, Production Records, Waste Manifests, Shipping Records, Generic Industry Data.

SUBSTANCES OBVIOUSLY >> 10,000 KG/YEAR

The NPRI substances obviously in use greater than 10,000 kg/year should be identified and placed on the list of reportable substances. For example, in a refinery, given the large throughputs of product streams (e.g.: gasoline), any NPRI listed substance in excess of 1% wt. would undoubtedly be much greater than 10,000 kg/year. A quick review of the chemical components of gasoline show at least 10 NPRI substances that fall into this category.

SUBSTANCES OBVIOUSLY << 5,000 KG/YEAR

The NPRI substances obviously in use less than 5,000 kg/year should be identified and placed on the list of non-reportable substances. For example, even though ETHIS may have predicted a certain chemical is on site, the experience of the Committee may be able to qualitatively assess that the chemicals are only used in small amounts.

SUBSTANCE USE UNCLEAR (5,000 - 10,000 KG/YEAR)

All substances that cannot be allocated to the >10,000 kg/year or the < 5,000 kg/year lists have to be quantified.

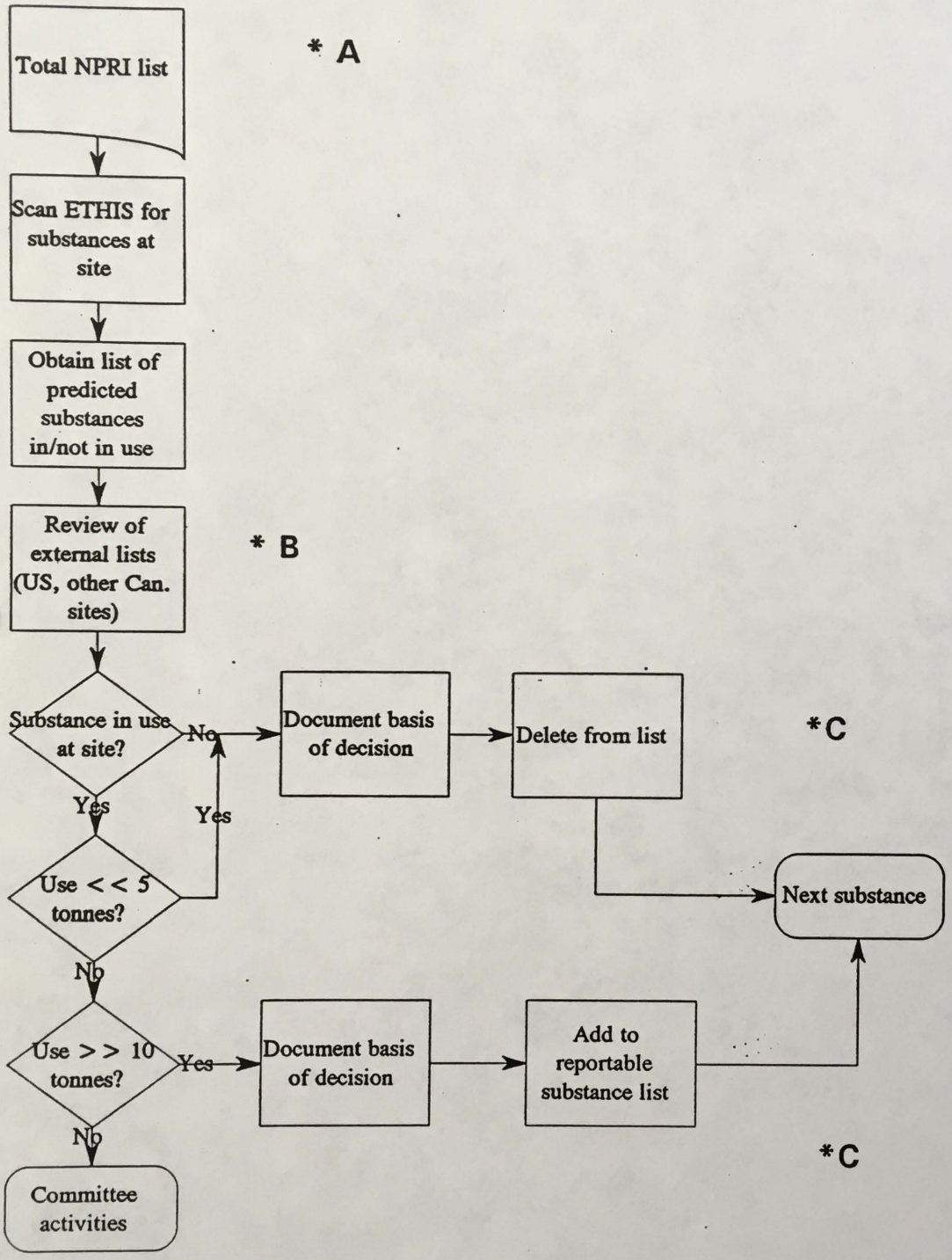
The QUANTIFICATION step is the third and final step of the identification process. This is where a small list of substances with site usage somewhere between 5,000 and 10,000 kg/year will be quantified to determine whether they are reportable or not. Current rationale is that the substances that are closer to 5,000 kg/year will be considered too small to be reportable. While substances that are quantified to be closer to 10,000 kg/year will require the quantification data to be entered into the EIS (Environmental Information System). In this way, these substances can be quickly re-assessed/quantified in future years. Substances calculated to be used in excess of 10,000 kg/year will obviously make the reportable list.

QUANTIFICATION STEPS

- Select NPRI substance.
- Identify chemical agent or material.
- Identify user/process unit or area of chemical agent/material.
- Identify stream(s) where substance or chemical agent is in use.
- Obtain stream throughput data.
- Obtain substance concentration (from or other source of chemical specification data).
- Perform calculation.
- Assess quantity in use.
- Allocate to appropriate list.

SUBSTNCS.ABC\TopChart
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Identification of Reportable Substances - Approach



(FOR ANNOTATIONS ON EACH MAJOR STEP IN ABOVE FLOWCHART, SEE SECTION 030-020)
(FOOTNOTES FOR *A, *B, *C, *D ARE AT THE END OF THE FLOWCHART)

FIGURE 3

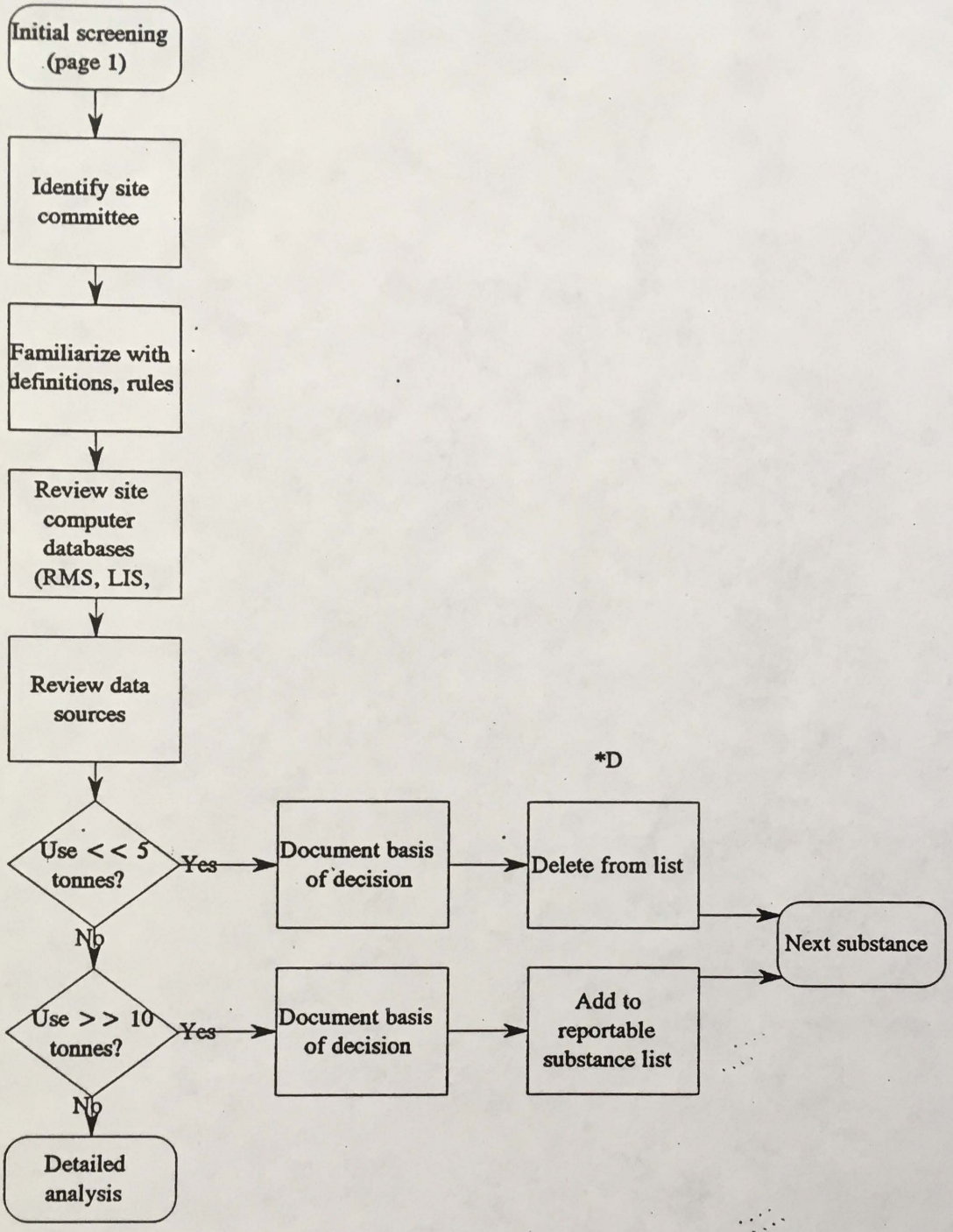

Initial screening (page 1)
Identify site committee
Familiarize with definitions, rules
Review site computer databases (RMS, LIS,
Review data sources
*D
Use << 5 tonnes?
Yes
Document basis of decision
Delete from list
Next substance
No
Use >> 10 tonnes?
Yes
Document basis of decision
Add to reportable substance list
No
Detailed analysis

FIGURE 3

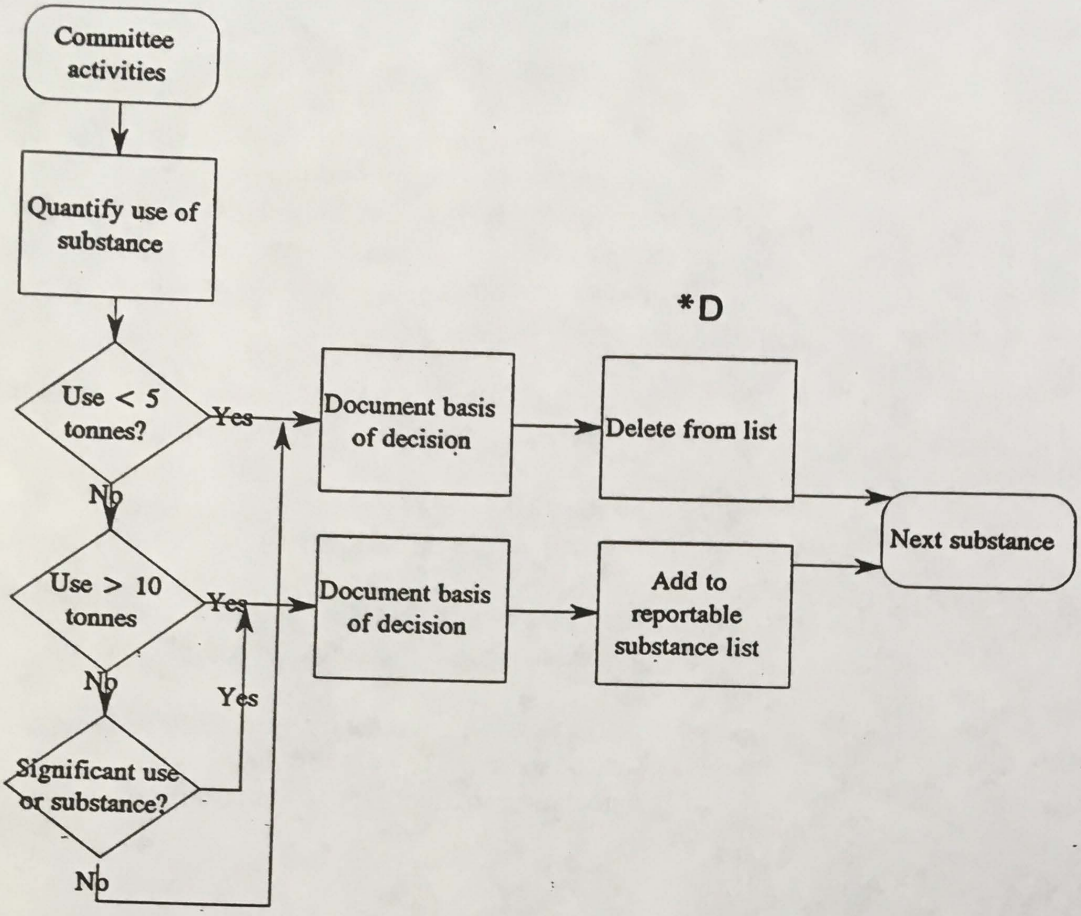

Committee activities
Quantify use of substance
*D
Use < 5 tonnes?
Yes
Document basis of decision
Delete from list
Nb
Use > 10 tonnes
Yes
Document basis of decision
Add to reportable substance list
Next substance
Nb
Yes
Significant use or substance?
Nb

FIGURE 3

FOOTNOTES TO APPROACH FLOWCHART

- A: 1993 NPRI Substance List = 178 chemicals.

NOTE: Sarnia site is defined as a single facility. The chemical plant and the refinery will report separately but for the identification of reportable substances step, both sites will examine themselves against their corresponding NPRI list of substances -- and generate a common list of reportable substances.

- B: present US databases include substance lists from Exxon Benecia and Billings refineries.

- C: boxes for Non-reportable and Reportable Substances are the same as on p. 2 of flowchart.

- D: boxes for Non-Reportable and Reportable Substances are the same as on p. 1 of flowchart.

- E: quantification invloves many steps. Please refer to text of section 030-020 and the example calculations of section 030-030 for more details.

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REPORTED SUBSTANCES AT EXXON REFINERIES & CHEM PLANTS -- 1991

	Exxon Refineries				Exxon Chem Plants		
Reportable Substance	Benlcia	Billings	Baton Rouge	Baytown	Baytown	Baton Rouge	NPRI
Acetone					Y	Y	Y
Acetonitrile						Y	Y
Ammonia	Y	Y	Y	Y	Y	Y	Y
Anthracene			Y		Y	Y	Y
Barium Compounds				Y			N
Benzene	Y	Y	Y	Y	Y	Y	Y
1,3 - Butadiene	Y	Y	Y	Y	Y	Y	Y
sec-Butyl Alcohol					Y	Y	Y
tert-Butyl Alcohol					Y	Y	Y
Carbon Tetrachloride	Y		Y	Y			Y
Chlorine	Y	Y	Y	Y	Y	Y	Y
Chloromethane					Y		Y
Chromium	Y			Y	Y		Y
Cobalt Compounds			Y			Y	Y
Copper Compounds				Y	Y		Y
Cresol		Y	Y			Y	Y
Cumene	Y	Y	Y	Y	Y	Y	Y
Cyclohexane	Y	Y	Y	Y	Y	Y	Y
Diethanolamine		Y		Y	Y		Y
Ethylbenzene	Y	Y	Y	Y	Y	Y	Y
Ethylene	Y	Y	Y	Y	Y	Y	Y
Ethylene Glycol		Y	Y	Y	Y	Y	Y
Formaldehyde			Y			Y	Y
Glycol Ethers	Y					Y	N
Hydrazine					Y		Y
Hydrochloric Acid			Y	Y	Y	Y	Y
Hydrogen Fluorjde		Y					Y
Isopropylidenediphenol						Y	Y
Lead Compounds	Y	Y	Y			Y	Y

FIGURE 4

REPORTED SUBSTANCES AT EXXON REFINERIES & CHEM PLANTS -- 1991

	Exxon Refineries				Exxon Chem Plants		
Reportable Substance	Benicia	Billings	Baton Rouge	Baytown	Baytown	Baton Rouge	NPRI
Maleic Anhydride						Y	Y
Methanol		Y	Y	Y	Y	Y	Y
Methyl Chloride						Y	N
Methyl Ethyl Ketone			Y	Y	Y	Y	Y
Methyl Methacrylate					Y		Y
2-Methoxyethanol				Y			Y
Methyl tert-butyl ether (MTBE)		Y	Y	Y	Y	Y	Y
Methyl Isobutyl ketone (MIBK)			Y	Y			Y
Naphthalene	Y	Y	Y	Y	Y	Y	Y
Nickel Compounds	Y				Y		Y
Phenol	Y		Y	Y	Y	Y	Y
Phosphoric Acid	Y		Y			Y	Y
Phthalic anhydride						Y	Y
Propylene	Y	Y	Y	Y	Y	Y	Y
Styrene				Y	Y	Y	Y
Sulphuric Acid	Y	Y	Y	Y	Y	Y	Y
Toluene	Y	Y	Y	Y	Y	Y	Y
Trichloroethane 1,1,1			Y			Y	N
1,2,4 - Trimethylbenzene			Y	Y	Y	Y	Y
o-xylene						Y	Y
Xylene (Mixed isomers)	Y	Y	Y	Y	Y	Y	Y
Zinc Compounds			Y	Y	Y	Y	Y

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FIGURE 4

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: IDENTIFYING REPORTABLE SUBSTANCES

SUBJECT: SAMPLE QUANTIFICATION CALCULATIONS

QUANTIFICATION CALCULATIONS

A number of examples of the quantification calculation process have been provided.

Problem: Substance A is on the NPRI list. It is a component of crude oil at a concentration of 2 - 5 wt%. If the crude oil throughput is 100,000 B/day and the crude density is 175 kg/B, will substance A be a reportable substance?

Solution: Rate of substance A in use =

100,000 B/day x 175 kg/B x 365 day/yr x 1 tonne/1000 kg x .03 = 191,625 tonnes/yr.

Since this exceeds 10 tonnes, substance A will be a reportable substance for the site, and the amount of substance A released to the environment will have to be calculated.

Note: Reportable substances are determined by assessing how much substance is used, with no consideration for the amount released.

Problem: Substance B is on the NPRI list. It is a component of crude oil at a concentration of .25 wt% . Crude oil throughput is 150,000 B/day. Substance B concentrates in the refining process and is known to be in a sidestream at 3%. If sidestream flowrate is 8000B/day at a density of 150 kg/B, should substance B be on the reportable list?

Solution: Substance B will be exempt from consideration in the crude oil stream because concentration is .25wt%, which is less than the deminimus exemption of 1% wt. But in a sidestream, substance B is concentrated to 3% wt. Therefore, the sidestream should be evaluated.

Rate of substance B in sidestream =

8000 B/day x 150 kg/B x 365 day/yr x 1 tonne/1000 kg x .03 = 13,140 tonnes/yr.

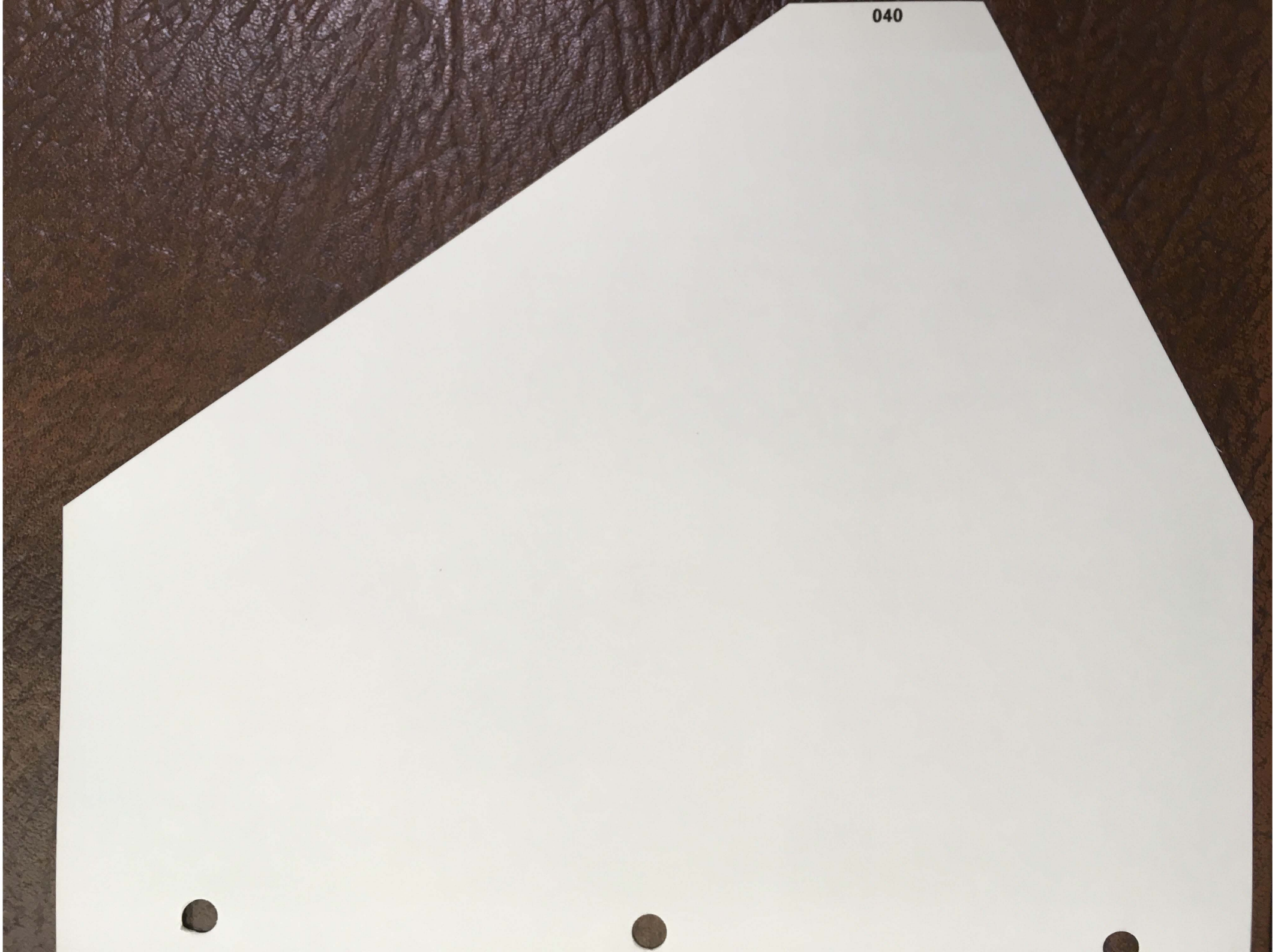
Since this exceeds 10 tonnes/yr, substance B must be included on the reportable list.

Problem: Substance C is on the list and is present in the C3/C4 stream to an alkylation unit at a concentration of .02 wt%. Stream flowrate is 2000 B/day and stream density is 100 kg/B.

Solution: As the concentration is less than 1 % the deminimus exemption applies and we would not include substance C in this stream. Even though the mass of substance C in the C3/C4 stream to the alkylation unit

2000 B/day x 100 kg/B x 365 D/yr x 1 tonne/1000 kg x .0002 = 14.6 tonnes/yr

is greater than 10 tonnes/year.


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IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: OVERVIEW

OVERVIEW

This section of the Guideline contains information on release calculation methodologies. First, there is a summary of the recommended methodologies (on a source basis). Then, the data requirements using each of the methodologiesare listed.

Following the recommended methodologies is important to standardize the quality and consistency of release inventories across Imperial Oil.

Minimum appropriate standard methods and release factors were determined through discussions with Exxon Research and Engineering. The following list should be updated as new methods develop and we gain experience as more accurate techniques are desired. For example, "stratified" factors will be used by facilities with formal valve leak monitoring and maintenance programs while general AP-42 factors that do not require sampling will be used by other facilities. It is also important to recognize the distinction between release calculation and release measurement. Release calculations are based upon industry standard published methods which use factors. These factors have been established as a means of summarizing actual release measurements that may have been performed many years ago. For Imperial Oil's first comprehensive inventory, the results will be primarily based upon calculations from these standard methods and factors, and will not be based upon actual measurements performed during 1993.

U.S. experience indicates that significant additional effort is required to progressively increase data accuracy. However, total estimated releases may be significantly reduced using more demanding methods.

RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS	OVERVIEW

Sections 040-030 provides the type and extent of data required to perform the 1993 release inventory calculations. The first year of an inventory is especially onerous with regard to data collection but much of the information collected in the first year can be used in subsequent years (e.g. tank dimensions).

RESPONSIBILITIES

See Administration section of Release Inventory Basis and Management Section.

PROJECTIONS

The NPRI reporting form asks for anticipated releases and transfers by substance for the next three reporting years. Constant values should be anticipated unless specific facility or operating changes are planned and have been approved.

SEASONAL VARIATION

According to environment Canada, a seasonal breakdown of releases of each substance is required if the releases during any quarter amount to less than 15% or greater than 35% of the total amount released.

Unless there are significant changes in operations during the reporting year, consider annual releases to be evenly distributed (25% per quarter).

Some seasonal variation in emissions occurs due to changes in ambient temperatures and product volatility. However, annual average calculations are acceptable because the API equations are based on yearly averages.

PROGRESS IN REDUCTION

Subsequent to the initial NPRI submission, facilities will be asked to indicate the principle reasons for year-to-year changes in release and transfer quantities of each reported substance. Changes are typically due to production levels, estimation methods, pollution prevention, abatement, accidents, spills and process turnarounds. Only significant changes should be flagged. Respondents must be able to substantiate reasons for change, especially pollution prevention or abatement.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: RELEASE CALCULATION METHODOLOGY SUMMARY

SOURCE	METHOD	COMMENTS
API Separators	Litchfield for oil layer CHEMDAT7, water layer	Emissions from oil layer to air, estimate % of API oil covered. Need to know the concentration of specific components.
Biox and Clarifiers	CHEMDAT7	Requires much information and concentrations of specific components.
Buildings	Measured	Usually a small source, combustion emissions calculated as per combustion section.
Co-generation	AP - 42	Quick, low cost, conservative emissions estimate.
Combustion	AP - 42	Recommended for fast, cheap, and defensible inventory. AP - 42 factors are average numbers and do take into account air preheat (affects NOx). CO2 & SOx calculated stoichiometrically.
Cooling Towers	AP - 42	Beware of chromium biocides and other chemical added upstream.
Dissolved Air Flotation & Induced Air Flotation	EPA-450/3-85-001A, 2/85	Applies to DAF's and to IAF's.
Exploration & Production	Several	Some methods same as in other sections (e.g. combustion).
Flares	AP - 42	Need mass flow and combustion efficiency (EPA has accepted 98% eff.).

RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

RELEASE CALCULATION METHODOLOGY SUMMARY

SOURCE	METHOD	COMMENTS
Fugitive Emissions	AP - 42	No field monitoring required. Requires component counts, use estimation approaches, usually 20% underestimate of number of components.
	Stratified	Used by facilities with formal leak detection and repair programs. More accurate and lower values.
Gas Turbines	Vendor estimate	Manufacturers usually have good combustion information. Fuel type and composition will affect emissions.
Internal Combustion Engines	AP - 42	Spark retard or lean burn practices lower NOx relative to AP - 42.
Non-Routine Events	Plant Records	Process upsets, start-ups/shutdowns, etc.
Process Units	Exxon/ Industry	ER&E recommends specific help with these big sources. Look downstream for measurements (e.g. CO boiler). (FCCU, coker, reformer, sulphur plant).
Process Vents	Measurement	Requires measurement of releases and analysis for compositional information.
Product Loading	AP - 42	Includes barges, tank trucks, tank cars, marine tankers. Different factors for splash vs submerged loading, crude vs gasoline loading.
Purchased Products	Inventory Records	How much purchased and how much used.
Secondary Emissions	Litchfield for oil layer CHEMDAT7, water layer	For landfarm to air emissions use CHEMDAT7.
Sewers	AP - 42	Requires the source counts, take refinery slop oil for component speciation.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: RELEASE CALCULATION METHODOLOGY SUMMARY

SOURCE	METHOD	COMMENTS
Spills	Plant Records	Need amount spilled, how much went to air, water and soil. Need to ensure data captured in current plant reports.
Tanks	API Methods	API Methods 2517, 2518, and 2519 for fixed, external and internal floating roof.
Vapour recovery	AP - 42	Requires uncontrolled loading emissions and efficiency factor. No sampling required.
Vehicle Refueling	EPA-450/3-75-046	1.38 grams of VOC per liter of gasoline.
Waste	Plant Records	Mass and composition of waste, on-site and off-site wastes.
Waste Water	Measured	Requires flowrate and water analysis (e.g. MISA).

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: DATA COLLECTION REQUIREMENTS (BY RELEASE SOURCE)

TYPICAL EXXON REFINERY HYDROCARBON RELEASES

SOURCE	APPROX.%	INFORMATION REQUIRED
Fugitive Emissions	50 to 60	Component counts and stream composition.
Non-Routine Releases	1	Quantity, composition, remedial action.
Off Site Disposal	1	Quantity, composition.
On Site Disposal	2	Quantity, composition.
Product Loading	3 to 9	Loading methods, composition, throughput.
Process Vents & Flares	3 to 9	Flow rates, composition, flare efficiencies.
Secondaries, Waste Water Treatment Plant	3 to 9	Flow rate, composition, temperatures, wind speed.
Storage Tanks	3 to 11	Construction, fluid composition, temperatures, wind speed, throughput.
Waste Water Effluent	3 to 9	Flow rate, composition.

API SEPARATOR EMISSION CALCULATIONS

GENERAL INFORMATION

Separator surface area.
% of surface covered with oil.
Controls (is separator covered?, are vapours vented to flare?).
Skimming frequency (oil withdrawal frequency).
Wastewater flowrates.
10 % True boiling point of oil.
Influent water temperature.
Influent oil concentration.
Ambient temperature.
Specific gravity of the oil layer.
Wind speed.
Water depth.

CHEMICAL SPECIATION

Raoult's law requires-

Weight percentage of NPRI substances present.
Molecular weight of these NPRI substances.
Vapor pressure of the pure substance at the liquid surface temperature.
Calculation of the mole fraction of the NPRI substances.
Average molecular weight of the combined non-NPRI substances in the liquid.

BIOX EMISSION CALCULATIONS

GENERAL INFORMATION

Wastewater flowrate.
Influent water temperature.
Influent oil concentration.
Ambient temperature.
Wind speed.
Water depth.
Surface area.
Surface agitation (% surface agitated).
(number, size, speed, & power of impellers).
Submerged aeration gas flow rate.
Bio-degradation rates.
Bio-mass concentration.

CHEMICAL SPECIATION

Raoult's law requires-
Concentration of NPRI substances present in the influent water.
Molecular weight of these NPRI substances.
Vapor pressure of the pure substance at the liquid surface temperature.
Calculation of the mole fraction of the NPRI substances.
Average molecular weight of the combined non-NPRI substances in the liquid.

BUILDING EMISSION CALCULATIONS

GENERAL INFORMATION	Combustion emissions sources. Refrigerant losses (plant records). Ventilation, fume hoods (flowrate, VOC concentration).
CHEMICAL SPECIATION	Based on component concentrations in exhaust gases.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: DATA COLLECTION REQUIREMENTS (BY RELEASE SOURCE)

COMBUSTION EMISSION CALCULATIONS

GENERAL INFORMATION

Combustion unit type (boiler, heater, steam generator, flare, incinerator, IC engine, gas turbine, cogen).
Fuel type.
Furnace size (BTU).
Annual service factor for each combustion unit.
Annual quantity of each fuel type burned.
Sulfur content of each fuel.
Carbon content of each fuel.
Flare combustion efficiency.

LARGE SOURCES

FCCU, coker, reformer sulfur plant, and natural gas plants are large sources of combustion emissions.
These very large source require especially careful estimates of unit capacities and operational practices

COOLING TOWER EMISSION CALCULATIONS

GENERAL INFORMATION	Water flowrate.
CHEMICAL SPECIATION	Raoult's law requires- Concentration of NPRI substances present in the influent water. Molecular weight of these NPRI substances. Vapor pressure of the pure substance at the influent water temperature. Calculation of the mole fraction of the NPRI substances. Average molecular weight of the combined non-NPRI substances in the liquid.

DAF AND IAF EMISSION CALCULATIONS

GENERAL INFORMATION

Minimum Information:
Wastewater flowrate
IAF covered/uncovered.

Improved Estimate for IAF only:
Influent water temperature
Influent oil concentration
Ambient temperature
Wind speed
Water depth
Surface area
Surface agitation (% surface agitated)
(number, size, speed, & power of impellers)
Submerged aeration gas flow rate.

CHEMICAL SPECIATION

Raoult's law requires-
Concentration of NPRI substances present in the influent water.
Molecular weight of these NPRI substances.
Vapor pressure of the pure substance at the liquid surface temperature.
Calculation of the mole fraction of the NPRI substances.
Average molecular weight of the combined non-NPRI s.

EXPLORATION & PRODUCTION RELEASE CALCULATIONS

SPECIFIC INFORMATION	All sources relevant TO AP-42 uses those factors. Sources not covered by AP-42, EPRCO has found or developed estimation methods. Contact Bob Steele of Exxon's EPRCO.

FUGITIVE EMISSION CALCULATIONS

GENERAL INFORMATION	Total number of components (valves, flanges, PRV's, compressors, pumps, drains). Physical state of process material (gas, light liquid, heavy liquid). Chemical composition of process material for emission speciation. The appropriate AP-42 factors. Areas of equal or similar chemical composition in unit P&ID's.
CHEMICAL SPECIATION	Weight percentage of NPRI substances present at greater than 0.1% in each stream of each unit. Speciation based on process material composition.

LOADING EMISSION CALCULATIONS

GENERAL INFORMATION

Annual throughput of each product.
Type of product being loaded (crude, gasoline, distillate, resid).
Type of vessel receiving the load (barge, ship, tank truck, tank car).
Chemical composition of material loaded.
Loading configuration (splash, submerged, bottom).
Vapor recovery unit efficiency, if used.

CHEMICAL SPECIATION

Raoult's Law requires-
Weight percentage of NPRI substances present at greater than 0.1% in the product.
Molecular weight of these NPRI substances.
Vapor pressure of the pure substance at the liquid temperature of loading.
Calculation of the mole fraction of the NPRI substances.
Average molecular weight of the non-NPRI substances in the product.

NON-ROUTINE EVENT CALCULATIONS

SPECIFIC INFORMATION

Sufficient information must be collected to quantify the amount of material released.
The material released must be adequately described to enable chemical speciation.
Chemical speciation will be performed as appropriate to the situation.
The media receiving the release must be identified.

PROCESS VENT EMISSION CALCULATIONS

SPECIFIC INFORMATION	Location and number of each process vent. Mass flow rate of vented material. Annual average concentration of NPRI substances being vented.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: RELEASE INVENTORY METHODOLOGY & DATA REQUIREMENTS

SUBJECT: DATA COLLECTION REQUIREMENTS (BY RELEASE SOURCE)

PURCHASED PRODUCTS RELEASE CALCULATIONS

SPECIFIC INFORMATION

Material purchased for the site.
Quantity of material purchased.
NPRI substances contained in these purchased products.
NPRI substances released to which media from these products.

SECONDARY EMISSION CALCULATIONS

GENERAL INFORMATION

Pits, sumps, basins, impoundments, lagoons and landfarms.

Information for no oil layer:
Wastewater flowrate
Influent water temperature
Influent oil concentration
Ambient temperature
Wind speed
Water depth
Surface area
Bio-degradation rates
Bio-mass concentration.

Additional information for oil layer:
Oil layer thickness
10% True boiling point of oil.

CHEMICAL SPECIATION

Raoult's law requires-
Weight percent of NPRI substances present in the oil/water
Molecular weight of these NPRI substances
Vapor pressure of the pure substance at the liquid surface temperature
Calculation of the mole fraction of the NPRI substances
Average molecular weight of the combined non-NPRI substances in the liquid.

SEWER EMISSION CALCULATIONS

GENERAL INFORMATION

Count number of sources (drains and junction boxes open to atmosphere).
Count number of controlled sources (with P-legs or seal pots).

CHEMICAL SPECIATION

Raoult's law requires-
Weight percent of NPRI substances present in the influent oil (take refinery slop oil for component speciation).
Molecular weight of these NPRI substances.
Vapor pressure of the pure substance at the liquid surface temperature.
Calculation of the mole fraction of the NPRI substances.
Average molecular weight of the combined non-NPRI substances in the liquid.

SPILL CALCULATIONS

SPECIFIC INFORMATION	Requires incident reports with accurate and complete information. Identify the material, product, or intermediate stream that was spilled. Quantification of the spill. Chemical speciation. Which media received the spill. See CPPI NPRI Suggestions Document for tips on appropriating spill portions to air and land.

STORAGE TANK EMISSION CALCULATIONS

GENERAL INFORMATION	Total number of tanks. Contents of tanks. Changes in tank service. Chemical composition of liquid stock. Exclude tanks with stocks of less than 0.1 psi vapor pressure.
CHEMICAL SPECIATION	Raoult's law requires - Weight percentage of NPRI substances present at greater than 0.1%. Molecular weight of these NPRI substances. Vapor pressure of the pure substance at the liquid surface temperature of the tank contents. Calculation of the mole fraction of the NPRI substances. Average molecular weight of the combined non-NPRI substances in the liquid.
FIXED ROOF TANKS (UNINSULATED)	Standing storage loss requires- Minimum information: Diameter Shell height Roof type, cone or dome Outside paint color Location Stock type Stock bulk temperature Stock vapor pressure, or Reid vapor pressure. Working loss requires-

Minimum information:
Stock vapor molecular weight
Stock vapor pressure, or Reid vapor pressure
Stock annual net throughput
Stock turnover rate to calculate Kn
Stock type
Working loss product factor.

Improved estimate:
Roof slope or dome radius
Breather vent settings
Daily average ambient temperature
Solar insolation
Atmospheric pressure
Stock vapor molecular weight
Stock liquid surface temperature.

EXTERNAL FLOATING ROOF TANKS

Standing storage loss requires-

Minimum information:
Stock vapor pressure, or Reid vapor pressure
Stock average storage temperature
Stock type
Tank diameter
Average wind speed at tank site
Product factor Kc.

Withdrawal loss requires-

Minimum information:
Annual net throughput
Type of stock
Average liquid stock density
Tank diameter
Condition of the tank shell
Clingage factor.

Improved estimate:
Tank construction, welded or riveted

Type of rim seal system
Type and number of roof fittings
Roof construction, pontoon or double deck
Molecular weight of stock vapor.

INTERNAL FLOATING ROOF TANKS

Standing storage loss requires-

Minimum information:
Stock vapor pressure, or Reid vapor pressure
Stock type
Tank diameter
Tank type, column or self supported
Product factor Kc.

Withdrawal loss requires-

Minimum information:
Annual net throughput
Stock type
Average liquid stock density
Tank diameter
Tank shell and column condition
Clingage factor
Number of columns
Effective column diameter.

Improved estimate:
Rim seal system type
Deck fitting types and numbers
Deck details, welded or bolted
Stock vapor molecular weight.

VEHICLE REFUELLING EMISSION CALCULATIONS

SPECIFIC INFORMATION	Annual amount of fuel loaded into vehicle fuel tanks. Chemical speciation via Raoult's law.

WASTE TRANSFER CALCULATIONS

SPECIFIC INFORMATION

Waste taken off site needs an accurate and complete manifest.
Destination of the waste.
Quantity of waste.
Chemical speciation of NPRI substances in the waste (not subject to 1% de minimus).
Ultimate destiny of waste (recovery/reuse/recycle, destruction, municipal sewage treatment plant, containment).
Names of receiving streams and water bodies.
Identification of off-site facilities to which waste was sent.

WASTE WATER EFFLUENT CALCULATIONS

SPECIFIC INFORMATION	Annual volumetric or mass of waste water effluent, ie Gigatonnes per year. Annual average concentration of each NPRI substance in the water, ie 0.03 ppm benzene.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: **EMISSION ESTIMATING GUIDE**

SUBJECT: **OVERVIEW**

Detailed explanations of methods to estimate releases from various sources can be found in "Exxon Research and Engineering, Emission Estimating Guidebook". (Draft issued in April 1993).

This version , prepared under the Code 500 Engineering Technology Research and Development program, contains sections on Fugitives, Tanks, Secondary, Transfer Operations and Combustion.

EMISSION ESTIMATING GUIDEBOOK

APRIL 1993

EXXON RESEARCH AND
ENGINEERING COMPANY

DRAFT

COMBUSTION

EMISSION ESTIMATING GUIDEBOOK

APRIL 1993

EXXON RESEARCH AND
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Emission estimating reduces a complex situation to a simple factor. With the exception of sulfur oxides ar carbon dioxide, the emissions from a given combustion unit depend strongly on the design of the unit, the fu burned, and the way the unit is operated. Other parameters determined by the plant location, such as ambie temperature and humidity, can also affect the emissions.

The large number of parameters affecting the emission make it unlikely that any single factor will satisfactori describe the emission rate. And, there are not enough combustion sources in a refinery or petrochemical pla to rely on statistics to give a good average for the facility. Each combustion unit is a unique device and a ideal emission estimating procedure should reflect this uniqueness. For some emissions, particularly NOx, large body of information has built up over the last two decades and the affect of many of the parameters c the emission can be individually estimated. Dealing simultaneously with many parameters is another matte with even the determination of whether the adjustments should be additive or multiplicative open to debat For many of the pollutants, including particulates, carbon monoxide, and hydrocarbons, there is no large bod of information to draw on.

From the above discussion it should be clear that we do not have the tools to determine an accurate emissic based on first principles. We provide in this guidebook the best tools and procedures at our disposal. Whil for any given unit the estimated emission may not agree with a measurement, the estimate is often more tha adequate for site emission inventories and tracking emission reduction performance following the installatic of control technology. And that is the job of emissions estimating: To provide an approximate answer in th absence of better information and without the cost of taking measurements.

If better information is available, for example a measurement of the emissions from a given unit, skip th procedures in this guidebook and convert the measurement to the units you want. In combustion emissic estimating, use measurements where available, but don't rush out to take measurements.

The emission estimates in this guidebook are expressed in weight of emission per unit of fuel burned. In mar cases this has involved converting emission factors that have been reported using other units, for example, th volume of fuel. The high heating value (HHV) of the fuel has been used for the conversions. Emission facto are given in both English and Metric units.

The guide is organized by combustion applications. Under each application, emission factors are given for eac of the pollutants. Since some pollutant related emission characteristics are common to all the combustic applications, the reader will often be referred back to the initial application where the characteristic is fir discussed. In this way, it is hoped that the reader will begin to understand how the emissions depend c combustion fundamentals.

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010-000	Introduction	Feb 93
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060-	Stationary Internal Combustion Engine	Feb 93
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Terms	Definitions
Emission Factors	Weight of pollutant emitted per unit of fuel consumed. In this Guide, they are presented as weight of pollutant emitted per unit of heat released by fuel (lb/MBtu or g/GJ).
GJ	Energy unit giga (10^9) Joules, used in high heating values.
High Heating Value (HHV)	Amount of heat released per unit of fuel fired based on liquid water as the combustion product. Lower heating value has the heat of water vaporization subtracted as product water remains as vapor.
Hydrocarbon Emissions	All organic carbon emissions. Sometimes it is separated into methane and non-methane.
Low Btu Gas (LBG)	Gas from partial combustion of refinery waste, e.g. coke, and contains high concentration of inerts, e.g. N2, from partial combustion step.
MBtu	Energy unit Million (10^6) British thermal units, used in high heating values.
Nm^3	Volumetric unit cubic meter at normal condition (0°C and 1 atm).
NOx Emissions	All nitrogen oxide emissions (NO, NO2, N2O, etc.) reported as NO2.
Particulate Emissions	All solid emissions reported as total suspended solids.
Refinery Fuel Gas (RFG)	A mixture of waste gases from various refinery operations, may be mixed with natural gas.
scf	Volumetric unit cubic feet at standard condition (60°F and 1 atm.)
SOx Emissions	Sulfur oxide emissions usually reported separately as SO2 and SO3.
Stoichiometric Conversion	Total conversion of reactants to products according to the theoretical reaction going to completion.
Toxic Air Pollutants	189 chemicals defined as toxic by the 1990 Clean Air Act of the United States.
USEPA or EPA	United States Environmental Protection Agency. It is responsible for formulating and implementing environmental regulations.

Convert From	To	Multiply By
vppm (in gaseous fuel)	mg/Nm^3 (in gaseous fuel)	0.0446x molecular weight of pollutant (g/mol)
lb/scf (gaseous fuel)	lb/MBtu	10^{+6}/(HHV) see table below
lb/gal (liquid fuel)	lb/MBtu	10^{+6}/(HHV) see table below
lb/MBtu	g/GJ	430

High Heating Values (HHV) of Common Fuels

Type of Fuel	High Heating Value (HHV)
Residual Oil	150,000 Btu/gal
Distillate Oil	140,000 Btu/gal
Natural Gas	1,050 Btu/scf
Diesel	145,000 Btu/gal

There are differences in the design and configuration between fired heaters and boilers,and these differences suggest that the emissions should be slightly different. However, there is insufficient information available on which to base separate emission factors. Accordingly, the same emission base estimating factor will be used in this manual for fired heaters and boilers. Variations between fired heaters and boilers will be taken into account in the burner intensity adjustments that is applied to the base emission factor.

NOx Emissions

NOx emissions are reported as nitrogen dioxide, NO2. While most of the NOx emissions from fired heaters and boilers are as nitric oxide, NO, the report as nitrogen dioxide, NO2, reflects that ultimately essentially all the NO is converted to NO2 by reactions in the atmosphere. In the discussion and calculations that follow references to NOx emissions are in terms of NO2.

As with any combustion source, there are two separate contributions which must be considered in determining the NOx emissions from fired heaters and boilers: the thermal NOx and the fuel nitrogen NOx contributions. The thermal NOx component is determined by flame temperature, residence time and oxygen level in the flame zone. While there is always thermal NOx, the fuel nitrogen component depends on the presence of fuel-bound nitrogen containing species in the fuel.

Both the thermal and fuel nitrogen components are particularly important when estimating emissions for fired heaters and boilers in refinery and petrochemical plants. At these plants it is the practice to burn a variety of fuels in the fired heaters and boilers. These fuels range from natural gas, through refinery fuel gas , to heavy liquids. In addition, preheated combustion air is sometimes used to increase the energy utilization of the facility. The different chemical compositions of the fuels and the air preheat change the flame temperature the most sensitive thermal NOx determinant. The refinery fuels often contain ammonia or other nitrogen containing constituents that contribute to the fuel nitrogen NOx.

AP-42 NOx Emission Factors

The USEPA Emission Estimating Handbook, commonly referred to as AP-42, provides a NOx estimate only for boilers. In Section 9.1 on Petroleum Refinery Emission Factors, process heaters are shown with the same emission factors as boilers. This suggests that as far as AP-42 estimating is concerned, boilers and fired heaters have the same base emission factor. This is likely due to a smaller database for emission estimates from fired heaters relative to the database for boilers.

The AP-42 tables for boiler NOx emissions reflect the thermal and fuel nitrogen contributions, but are not precise enough to provide the flexibility needed to cover the range of fired heater and boiler operation encountered in the refinery and chemical plant. AP-42 gives the emissions by boiler size and fuel type, as shown in the following table.

Extracted From AP-42 NOx Emission Factors For Boilers in lbs NO_2/MBtu Fired

Fuel	Boiler Size		
	< 10 MBtu/hr	10-100 MBtu/hr	> 100 MBtu/hr
Natural Gas	0.10	0.13	0.52
Distillate Fuel Oil	0.14	0.14	-
Residual Fuel Oil	0.37	0.37	0.45

Note: Source is USEPA AP-42, Sections 1.3 and 1.4

In the AP-42 extract above, the fuel nitrogen NOx contribution is reflected in the higher number shown for the residual fuel oil. However this number is only indicative of the direction of the effect. A footnote to AP-42 Table 1.3.1, indicates that emissions are strongly related to the fuel nitrogen content and presents a more accurate empirical relationship. The thermal NOx contribution is seen in the higher estimate for NOx from natural gas firing for the larger size boiler. This increase reflects the greater likelihood of using preheated combustion air with larger boilers.

Recommended Method for Determining the NOx Emission Factor

The emission estimating method that will be used in this guidebook for fired heaters and boilers is similar in procedure to AP-42 but includes additional parameters. It will involve separately determining the thermal and fuel nitrogen NOx contributions and then adding these together to obtain the overall emission estimate in the absence of any NOx reduction technologies. The effect of the NOx reduction technologies on the emission estimate will be woven into the process at the appropriate place in the calculations.

The thermal NOx contribution could be satisfactorily estimated if we knew the flame temperature. While there is a contribution from the oxygen level available to the flame, fired heaters and boilers are usually operated at an air to fuel ratio that is only slightly above stoichiometric in order to maximize energy efficiency. At these oxygen levels the oxygen concentration correction is not considered significant. Oxygen levels and residence time in the flame zone will not be considered in the emission estimating procedures that we will use.

The flame temperature is determined by the fuel composition, the air preheat, the relative humidity and the heat removal rate. A calculation of the flame temperature would consider each of these contributing factors and would be acceptable for relating NOx emissions. However due to the difficulty in calculating the effect of heat removal rate, the calculated adiabatic flame temperature is usually used as a surrogate. There are programs to calculate the adiabatic flame temperature. Such a calculation is considered outside the bounds of this guide but should be considered for complex refinery fuel gas mixtures.

The intensity of the burner, a measure of the heat release per volume of burner space or flame space als affects NOx emissions. A high intensity burner is a forced draft burner, with high pressure drop, designed t provide a high degree of mixing between the fuel and the combustion air. This results in a zone of high hea release, with corresponding high temperatures, and increased NOx production. High heat intensity burners ar usually found in boilers, where uniform temperature profiles are less important. They can nearly double th NOx emission rate.

Accordingly, the thermal NOx emission estimating method used needs to account for each of the followin contributing factors individually: 1) The fuel composition, 2) the air preheat, 3) the humidity, 4) and th intensity of the burner operation. The estimating approach which will be used builds on the method develope by Golan and Juedes of ER&E (EE.128E.91) and many of the adjustment factors are taken from their stud of Exxon furnaces.

The fuel nitrogen NOx contribution will be determined in two steps. First the NOx equivalent to the fue nitrogen contained in the fuel will be determined by stoichiometry. This determination will then be multiplie by a factor that reflects a varying fraction of the initial fuel nitrogen that is converted to NOx.

The effect on the NOx emission of NOx reduction technologies can be complicated. Some of the technologie are applied at the early stages of the combustion process and have an immediate impact on reducing flam temperature and/or local oxygen concentrations, and with this reducing the thermal NOx emissions. Other NO reduction technologies work on the back-end of the combustion process, after combustion has been completed These technologies reduce equally well the thermal and fuel nitrogen NOx emissions. Accordingly, the variou NOx reduction technologies will need to be taken into account at different places in the calculation procedure There have been some indications that the control technologies that works on the combustion process, such a low NOx burners, can lessen fuel nitrogen conversion, but we have insufficient data to substantiate a significar reduction and will not adjust for this effect.

Particulate Emissions

Two types of particulate estimates are encountered. Total suspended particulates (TSP) represents the entir range of particulates and was the first particulate matter designation used in U.S. regulations. More recently PM_{10}, the particulate fraction with particles less than 10 microns (0.001 cm), regulations have also been adopte in the U.S.

The emission of particulates is very dependent on the fuel used. Gaseous fuels usually produce almost n particulates, while the heavy fuels, such as residual fuel oils or steam cracker tars, produce high levels c particulates. The sulfur content and the Conradson Carbon Number, a measure of the refractory nature of th fuel, have at times been used to refine the estimate of particulates produced by a given fuel. A relationshi involving the sulfur content is part of the AP-42 method for particulate matter emission estimating, but has no been used in this guide.

The AP-42 emission factors will be used for estimating total suspended particulates in this guide. There is nc a sufficient database for developing emission factors for PM_{10} particulates. If an estimate for PM_{10} emission is needed, we suggest using one-third of the TSP value.

Carbon Monoxide and Hydrocarbon Emissions

While it is likely that the emissions of both carbon monoxide and hydrocarbons depends on flame temperature residence time in the flame, and oxygen content, as well as on the composition of the fuel, there is insufficien data or understanding to develop the relationships. Accordingly, carbon monoxide and hydrocarbon emissio estimates will be taken directly from AP-42.

The AP-42 emission estimates for both of these emissions are fuel and combustion unit size dependent. Unde hydrocarbons, AP-42 provides a separate emission estimate for methane and for non-methane hydrocarbons.

SOx Emissions

Sulfur oxide emission estimates are based on the sulfur content of the fuel. The emission estimate for SO. assumes a stoichiometric conversion of 100 percent of the fuel sulfur to SO2. To be conservative, the mos SO2 that can form and the most SO3 that can form are both estimated, even if the sum is equivalent to m than 100% of the total sulfur. AP-42 suggests no formation of SO3 from gaseous fuels and conversion of 1 of the fuel sulfur to SO3 when firing fuel oils. We recommend using 3% of the fuel sulfur converted to SO when firing liquid fuels. No conversion of fuel S to SO3 is assumed when firing gaseous fuels.

Even though SO3 is also a product of combustion, it is reported as, and assumed to be included as SO2. Th SO3 approach to equilibrium values is slow and very dependent on the nature of any catalytic surfaces that ma be present. Vanadium and chromium oxides, which may be present when firing heavy fuel oils, hasten th approach to equilibrium values of SO3.

NOx Emissions

The emission estimating method that will be used for fired heaters and boilers involves separately determining the thermal and fuel nitrogen NOx contributions and then adding these together to obtain the overall emission estimate in the absence of any NOx reduction technologies. The effect of the NOx reduction technologies on the emission estimate will be woven into the process at the appropriate place in the calculations.

Step 1 - Collect the fuel properties and operating conditions

Fuel H2 Content (%):_____

Combustion Air Preheat Temperature (°F):_____

Average Relative Humidity at Site (%):_____

Unit Load Factor (%):_____

Average Temperature at Site (°F):_____

Burner Intensity Classification: High _____or Normal_____

Flue Gas Recirculation (%):_____

Fuel Nitrogen Content (wt. %):_____

Fuel Firing Rate (MBtu/hr):_____

Fuel HHV (appropriate units)_____

NOx Reduction Technologies Used:_____

Step 2 - Determining the base thermal NOx emission factor

Based on the type of fuel used select the most appropriate base thermal NOx emission factor from Table FHB.1. If the fuel has appreciable H2 content (Step 1), multiply the factor from Table FHB.1 by the factor from Table FHB.2.

Step 3 - Adjusting for at-the-source NOx control technology

Based on NOx control technology used, lookup the at-the-source NOx adjustment factor from Table FHB.3. If no at-the-source NOx reduction has been used, the NOx adjustment factor is 1.0.

Step 4 - Further adjustment for flue gas recirculation

If flue gas recirculation is used for NOx control, then based on percent of flue gas recirculated, look up the flue gas recirculation adjustment factor from Table FHB.4. If flue gas is not recirculated the adjustment factor is 1.0.

Step 5 - Adjusting for air preheat

Based on the combustion air preheat temperature (Step 1), lookup the air preheat adjustment factc in Table FHB.5.

Step 6 - Adjusting for moisture content

Based on the relative humidity and temperature at the operating location (Step 1), lookup the weigh of water per weight of dry air in Figure FHB.1. Using this value, determine the NOx moistur adjustment factor from Figure FHB.2 or Table FHB.6.

Step 7 - Adjusting for the load factor of the furnace or boiler

Based on the load factor (Step 1), lookup the load factor adjustment factor from Table FHB.7.

Step 8 - Adjusting for burner intensity

If the burner selected (Step 1) is one that has been found to have high intensity heat release, looku the burner intensity adjustment factor from Table FHB.8.

Step 9 - Calculate the thermal NOx emission factor

Multiply the Base Thermal NOx Emission Factor (Step 2) by the adjustment factors from Steps 3 4, 5, 6, 7 and 8. The result is in lb NO2/MBtu fired.

Thermal NOx Emission Factor= Step 2 x Step 3 x Step 4 x Step 5 x Step 6 x Step 7 x Step

Step 10 - Calculate the base fuel nitrogen NOx contribution assuming all the fuel nitrogen goes to NO2. Th calculation is to be done in lb NO2/MBtu fired.

Perform a stoichiometric calculation using the data collected in Step 1.

$$\frac{\frac{y\ lb\,N}{lb\ fuel}}{\frac{x\ MBtu}{lb\ fuel}} \times \frac{MW_{NO_2}}{MW_N} = \frac{46\ y}{14\ x}\ \frac{lb\ NO_2}{MBtu}$$

Step 11 - Adjusting for fuel nitrogen conversion

Based on the fuel nitrogen content (Step 1), lookup the fuel nitrogen conversion adjustment factor from Table FHB.9.

Step 12 - Calculate the fuel nitrogen NOx contribution

Multiply the Base Fuel Nitrogen Contribution (Step 10) by the adjustment factor in Step 11. The result is in lb NO2/MBtu fired.

Fuel Nitrogen NOx Emission Factor = Step 10 x Step 11

Step 13 - Adjusting for post-combustion NOx control technology

Based on NOx control technology used, lookup the post-combustion NOx adjustment factor from Table FHB.10. If no post-combustion NOx reduction has been used, the post-combustion NOx adjustment factor is 1.0.

Step 14 - Calculate the overall NOx emission factor

Add the thermal NOx (Step 9) and Fuel nitrogen (Step 12) contributions and multiply the sum by the post-combustion NOx reduction factor (Step 13) . The results are in lbs NO2/MBtu fired.

Overall NOx Emission Factor = (Step 9 + Step 12) x Step 13

Step 15 - Calculate the overall NOx emission

Multiply overall NOx emission factor (Step 14) by firing rate in units of MBtu/yr to obtain annual NOx emission.

Particulate Emissions

Particulate emission estimates will be taken directly from AP-42.

Step 1 - Based on the fuel type and particulate estimate required, lookup the emission factor from Table FHB.11.

Step 2 - Calculate the particulate emission by multiplying the particulate emission factor (Step 1) by firing rate in units of MBtu/yr to obtain annual particulate emission.

Carbon Monoxide and Hydrocarbon Emissions

Carbon monoxide and hydrocarbon emission estimates will be taken directly from AP-42. The AP-42 estimate for both of these emissions are fuel and combustion unit size dependent. AP-42 provides a separate emissio estimate for methane and for non-methane hydrocarbons.

Step 1 - Based on the fuel type, lookup the emission factors for carbon monoxide and hydrocarbons fron Table FHB.12.

Step 2 - Calculate the carbon monoxide and hydrocarbon emissions by multiplying the carbon monoxide an hydrocarbon emission factors (Step 1) by firing rate in units of MBtu/yr to obtain annual carbo monoxide and hydrocarbon emissions.

SOx Emissions

Sulfur oxide emission estimates are based on the sulfur content of the fuel. The emission estimate for SO2 assumes a stoichiometric conversion of 100 percent of the fuel sulfur to SO2.

Step 1 - Conduct a stoichiometric calculation converting all fuel sulfur to SO2.

Note: See Sample Problem, Section 200-001, page 5, for an example of the stoichiometric calculation for SO2.

Emission Estimating Guide	Combustion-040-003
Section: Fired Heaters and Boilers	**Subject: Table FHB.1** Base Thermal NOx Emission Factor

Scope

This is the starting point for thermal NOx emission factors. It reflects the contribution to thermal NOx of the specific fuel used.

References

Atmospheric Emission Inventory Manual, M. N. Herman, EE.4DB.83, July 1983
Rotterdam Refinery NOx Emissions Assessment Test Program, D.C. Rigano, 87 ECS1-88, April 1987
Revised Thermal NOx Emissions for Rotterdam Flexicoker Project, E.F. Kiczek, 84 MATL 391, May 1984
Baytown Refinery Cogeneration Project Study

Background

The major factor modelled by this table is the effect of fuel composition on the adiabatic flame temperature. As an example, a low Btu gas has a lower NOx emission than natural gas because of the flame temperature moderating effect of the diluents in the low Btu gas.

Table FHB.1
Fired Heaters and Boilers Base Thermal NOx Emission Factors

Fuel	NOx Emission Factors	
	lb/MBtu	g/GJ
Methane	0.13	56
Refinery Fuel Gas	0.16	69
Low Btu Flexicoker Gas	0.07	30
No.2 Fuel Oil	0.13	56

Note: Composition for fuels used in Table FHB.1 are:

Component	Low Btu Gas (LBG)	Refinery Fuel Gas (RFG)
C_1	0.8 mole %	50.0 mole %
C_2	0.0	15.0
C_3	0.0	6.0
C_4	0.0	3.0
CO	23.9	0.0
CO_2	5.6	1.0
H_2	14.7	23.0
N_2	51.4	2.0
H_2O	3.6	0.0
H_2S	50.0 (VPPM)	50.0 (VPPM)
COS	380.0 (VPPM)	0.0 (VPPM)
CH_3SH	60.0 (VPPM)	0.0 (VPPM)

Scope

Adjusts the base thermal NOx emission factor for the increase in adiabatic flame temperature resulting fro hydrogen (H2) in the fuel.

References

Fired Heater NOx Prediction Tool, L. P. Golan and D. L. Juedes, EE,128E.91, December, 1991

Background

Molecular hydrogen (H2) has a very high adiabatic flame temperature. Therefore hydrogen-rich fuels will ha higher flame temperatures and will generate higher levels of NOx. Many refinery and petrochemical pla fuels include waste gases from the operations and some of these waste gases contain hydrogen, sometimes large amounts.

Accurately determining the fuel hydrogen effect on NOx emissions would be based on the calculated adiabat flame temperature for the fuel mixture (including the H2 content). However such an approach is n recommended for initial emission estimates. The adjustment that will be used is an approximation for the NO increase resulting from the hydrogen in the fuel and will be applied to the base thermal NOx emission fo fuel.

Table FHB.2
Fired Heaters and Boilers Fuel Hydrogen Adjustment Factors

H2 Content (vol %)	0	10	20	40	60
Adjustment Factors	1.0	1.03	1.09	1.25	1.67

Scope

Adjusts the thermal NOx emission factor for the reduction provided by at-the-source NOx reductio technologies. These technologies include flue gas recirculation and low NOx burners.

References

Background

The at-the-source NOx control technology adjustment factor is a modifier that is applied to the base fue composition factor to account for burner design changes which reduce NOx emissions by reducing flame temperature or changing the local oxygen concentration.

Three major technologies are used for this purpose: Low NOx burners (LNB), flue gas recirculation (FGR) and ultra-low NOx burners (UNLB). UNLBs are a combination unit in which the advantages of low NO burners and flue gas recirculation can be found in one unit. If flue gas recirculation (FGR) is used, select the adjustment factor from Table FBH.4 depending on the amount of FGR used.

Table FHB.3
Fired Heaters and Boilers At-The-Source NOx Control Technology Adjustment Factors

Technology	Adjustment Factors
None	1.0
LNB staged fuel	0.33
LNB staged air	0.6
Flue Gas Recirculation	See Table FHB.4
Ultra Low NOx Burner	0.3

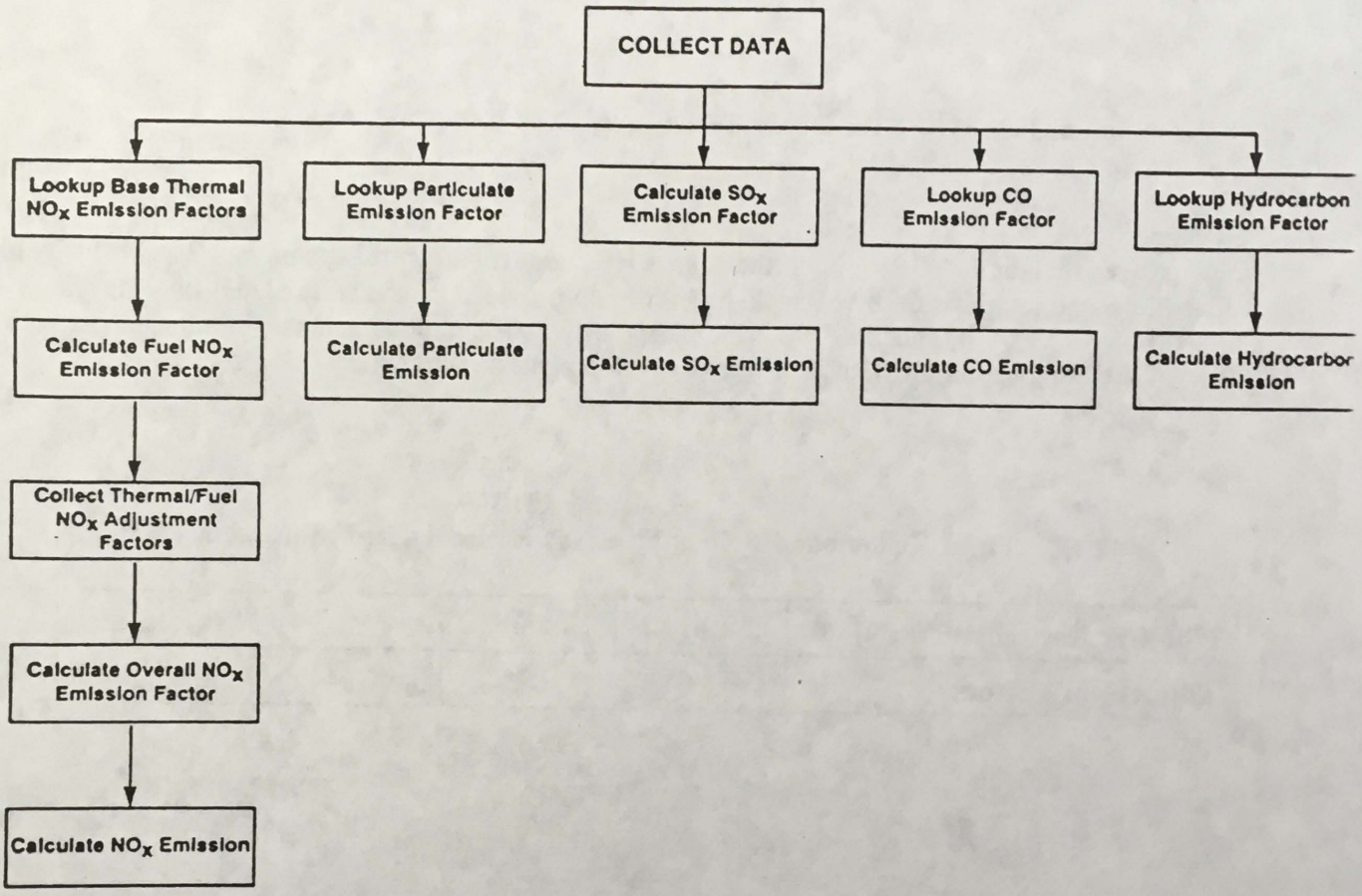
The first, and often the most time consuming, step in determining emission factors is to collect the informatio that one needs to preform the calculations. Unfortunately, there is no one central location in a refinery c chemical plant where all the information can be found. At sites where emission reporting has never been don before, it may take some detective work to find all the information. Traditionally, however, the financi departments keep good records of purchasing of raw materials and selling of products. As a result, th financial reports may be the best place to start. Energy conservation projects were the first to maintain energ consumption records and some similar information may be found there. And with some vigorous, and some time creative, analysis of data intended for different purposes, it is possible to gather all the information on needs. The following table is an attempt to direct the user of this manual to possible sources of information

Data	Unit	Where
Fuel type	N/A	1, 2, 3, 4
Fuel Nitrogen Content	wt. %	6, 7
Fuel Sulfur Content	wt. %	6, 7
Fuel Hydrogen Content	wt. %	6, 7
Fuel HHV	Btu/gal liquid Btu/scf gas	2, 3, 7
Actual Fuel Firing Rate	MBtu/hr.	1, 2, 3, 4, 5
Unit Load Factor	% of full load	2, 3, 5
Burner Intensity Classification	high or low	8
Air Preheat Temperature	F	1, 2, 3
Temperature at Site	F	9, 10
Relative Humidity at Site	%	9, 10
NOx Control Technology		
At-the-source	N/A	8
Flue Gas Recirculation	% recirculated	8
Post-Combustion	N/A	8

1) Daily furnace report
2) Monthly operating summary
3) Monthly energy conservation report
4) Financial report for fuel cost/allocation
5) Annual production report
6) Environmental engineering
7) Facility laboratory
8) Process or mechanical engineering
9) Local Meteorological stations
10) Almanac

The following page shows a block diagram of steps one needs to take to compete the emission estimatio process.

BLOCK DIAGRAM OF FIRED HEATERS AND BOILERS EMISSION ESTIMATION



EPA GRAPHIC DESIGN 3/93-10499-01D

Scope
Used to adjust NOx emission factor for the cooling effect on adiabatic flame temperature from recirculatin flue gas.

References
Introduction to Coen Low NOx Burner Techniques, Coen Company, Inc.

Background
Flue gas recirculation (FGR) is an at-the-source NOx reduction control technology that works by lowering th adiabatic flame temperature by balancing the dilution provided by the recirculated flue gas with the increase preheat provided by the hot flue gas. Flame stability considerations generally limit flue gas recirculation t 20% of the combustion air, although recent developments are stretching FGR to 30%.

Table FHB.4
Fired Heaters and Boilers Flue Gas Recirculation Adjustment Factors

Flue Gas Recirculation (%)	0	5	10	15	20
Adjustment Factors	1.0	0.6	0.4	0.3	0.2

Scope

Adjusts the base thermal NOx emission factor for the increase in adiabatic flame temperature resulting from preheat of the combustion air.

References

Fired Heater NOx Prediction Tool, L.P. Golan and D.L. Juedes, EE.128E.91, December 1991

Background

The air preheat correction factor is a correction relative to the base thermal NOx emission factor. The air preheat factor reflects the change in flame temperature as the temperature of the combustion air is changed. It can be a very significant correction at the high air preheat used in some Exxon furnaces and boilers.

Table FHB.5
Fired Heaters and Boilers Air Preheat NOx Adjustment Factors

Air Preheat Temp. (°F)	< 50	50	100	200	300	400	500
Adjustment Factors	1.00	1.00	1.00	1.10	1.32	1.60	1.86

Scope

Adjusts the base thermal NOx emission factor for the decrease in adiabatic flame temperature resulting from moisture in the combustion air or moisture deliberately added in the form of water or steam injection.

References

Alternative Control Technology Document - Stationary Combustion Gas Turbines, EPA July 1991 (Draft)
Fired Heater NOx Prediction Tool, L.P. Golan and D.L. Juedes, EE.128E.91, December 1991
Environmental Control Practice Manual, Exxon Chemical Company

Background

The moisture adjustment factor is a correction relative to the base thermal NOx emission factor. It reflects changes to the flame temperature from the cooling by the diluent provided by the moisture content of the combustion air or moisture that is deliberately added in the form of water or steam injection. It can be a significant effect at high relative moisture contents. (If relative humidity of air is known, use Figure FHB.1 to determine the moisture content in lb water/lb dry air). Three references have generated consistent results. These data are shown in Figure FHB.2. Table FHB.6 is extracted from this figure.

Table FHB.6
Fired Heaters and Boilers Moisture Content NOx Adjustment Factors

Moisture Content (lbs H20/lb dry air)	0	0.01	0.02	0.03	0.04	0.05
Adjustment Factors	1.0	0.79	0.67	0.53	0.41	0.29

Scope

Adjusts the base thermal NOx emission factor for the change in adiabatic flame temperature and flame zon gas residence time resulting from changes in unit operating load from the design load.

References

U.S. EPA AP-42, Figure 1.4-1 as shown in Fired Heater NOx Prediction Tool, L.P. Golan and D. L. Juedes EE.128E.91, December 1991

Background

The load adjustment factor reflects the change in intensity in the flame zone as the load of the furnace or boile is changed. For example, the change in intensity that accompanies a reduction in load reflects the smaller hea release under low load conditions while the heat removal surface in the heater or boiler has remained the same Load reduction is an easy way to quickly reduce NOx emissions for a short period of time, for example, durin a period of ozone alert . It does however come at a high cost, the underutilization of the unit.

Table FHB.7
Fired Heaters and Boilers Load NOx Adjustment Factors

Load % of Design Rating	40	60	80	100
Adjustment Factors	0.36	0.47	0.66	1.0

Scope
Used to adjust the base NOx emission factor for the effect of high burner intensity (heat release rate per volum of flame zone or enclosure).

References
Emission Estimates for FLEXICOKING Unit, C.B. Barbre, 87.ECS1.368, Nov. 20, 1987.

Background
The burner adjustment factor accounts for the volumetric heat release rate of the burner. High intensity burners are forced draft burners designed to provide a high degree of mixing between the fuel and the combustion air. This mixing provides a concentrated heat release that raises the local flame temperature and therefore the NOx emission. NOx emission levels from high intensity burners can be up to nearly twice that of lower intensity burners.

There is not a clear definition to help choose whether a given burner is high or low intensity, but some general guidelines can be given. Low intensity burners are usually natural draft burners with burner intensity on the order of 0.15 to 0.25 MBtu/hr ft^3 flame volume. High intensity burners are usually forced draft burners w pressure drop of 4 to 15 in. H2O and burner intensity at 0.3 to 0.5 MBtu/hr ft^3 flame volume. On an enclosu volume basis (the volume of the firebox) high intensity burners can have heat release rates greater than 70,000 Btu/hr ft^3 versus rates of about 3,000 Btu/hr ft^3 for low intensity burners. Many boilers fit this description but some Exxon fired heaters are also high intensity. The major difference between the two burner types is that the high intensity burner achieves much more intense mixing of fuel and air.

Lacking other information, use the high burner intensity factor for packaged boilers and pyrolysis furnaces. Use the normal burner intensity factor for other fired heaters and boilers.

Table FHB.8
Fired Heaters and Boilers Burner Intensity Adjustment Factor

Burner Intensity	Adjustment Factors
High	1.8
Normal	1.0

Scope
Adjusts the calculated fuel bound nitrogen NOx equivalent to reflect that all of the fuel nitrogen is not converted to NOx.

References
Fire Heater NOx Prediction Tool, L.P. Golan and D.L. Juedes, EE.128E.91, December 1991.

Background
The fuel nitrogen conversion factor reflects that all of the fuel nitrogen is not completely converted to NOx. Some of the fuel nitrogen reacts with hydrocarbon fragments in the flame or with nitrogen oxides to form nitrogen gas, N2. The table gives the fraction of fuel nitrogen converted to NOx for different initial levels of fuel nitrogen content. Low levels of fuel nitrogen are completely converted, with higher nitrogen containing fuel levelling off at a conversion of about 30%.

Table FHB.9
Fired Heaters and Boilers Fuel Nitrogen Conversion Factors

Fuel Nitrogen (wt%)	< 0.05	0.05	0.1	0.3	0.5	1.0
Conversion Factors	1.00	0.87	0.78	0.53	0.38	0.32

Scope

Adjusts the thermal NOx emission factor for the reduction provided by post-combustion NOx contr technologies. These technologies include Thermal DeNOx and selective catalytic reduction.

References

Background

The post-combustion NOx control technology adjustment factor is a modifier that is applied to the overa thermal and fuel nitrogen NOx emission factor to account for technologies that are applied downstream of th combustion process to destroy some of the NOx that was emitted by the combustion unit. The two prevale technologies used for this purpose are the Exxon Thermal DeNOx and Selective Catalytic Reduction (SCF processes. Both of these processes use NH3 to destroy NOx. **The post-combustion NOx control technolog adjustment factor is applied to the overall NOx emission factor** and is the last correction made.

Table FHB.10
Fired Heaters and Boilers Post-Combustion NOx Control Technology Adjustment Factors

Technology	Adjustment Factors
None	1.0
Thermal DeNOx	0.4
SCR	0.15

Scope
This table contains the particulate emission factors.

References
Compilation of Air Pollutant Emission Factors, AP-42, 4th ed. September 1985

Background
This table is taken directly from AP-42.

Table FHB.11
Fired Heaters and Boilers Total Suspended Particulate (TSP) Emission Factors

Fuel	Particulate Emission Factors[a]	
	lb/MBtu	g/GJ
Natural Gas[b]	0.001-0.005	0.41-2.0
Distillate Fuel Oil	0.013	5.7
Residual Fuel Oil No. 4	0.047	20
Residual Fuel Oil No. 6	0.02 + 0.066 x (fuel sulfur weight %) in lb/MBtu	

Notes: (a) Converted from AP-42, 9/85, using fuel heating values from Section 030-001.

(b) AP-42 provides a range for particulate emissions from natural gas firing. Either of the values is small and usually contributes insignificantly to the total plant particulate emissions. ER&E's recommendation has been to use the higher end of the range for emission estimating purposes.

Scope
This table contains the CO and hydrocarbon emission factors.

References
Compilation of Air Pollutant Emission Factors, AP-42, 4th ed. September 1985, Tables 1.4-1 and 1.3-1.

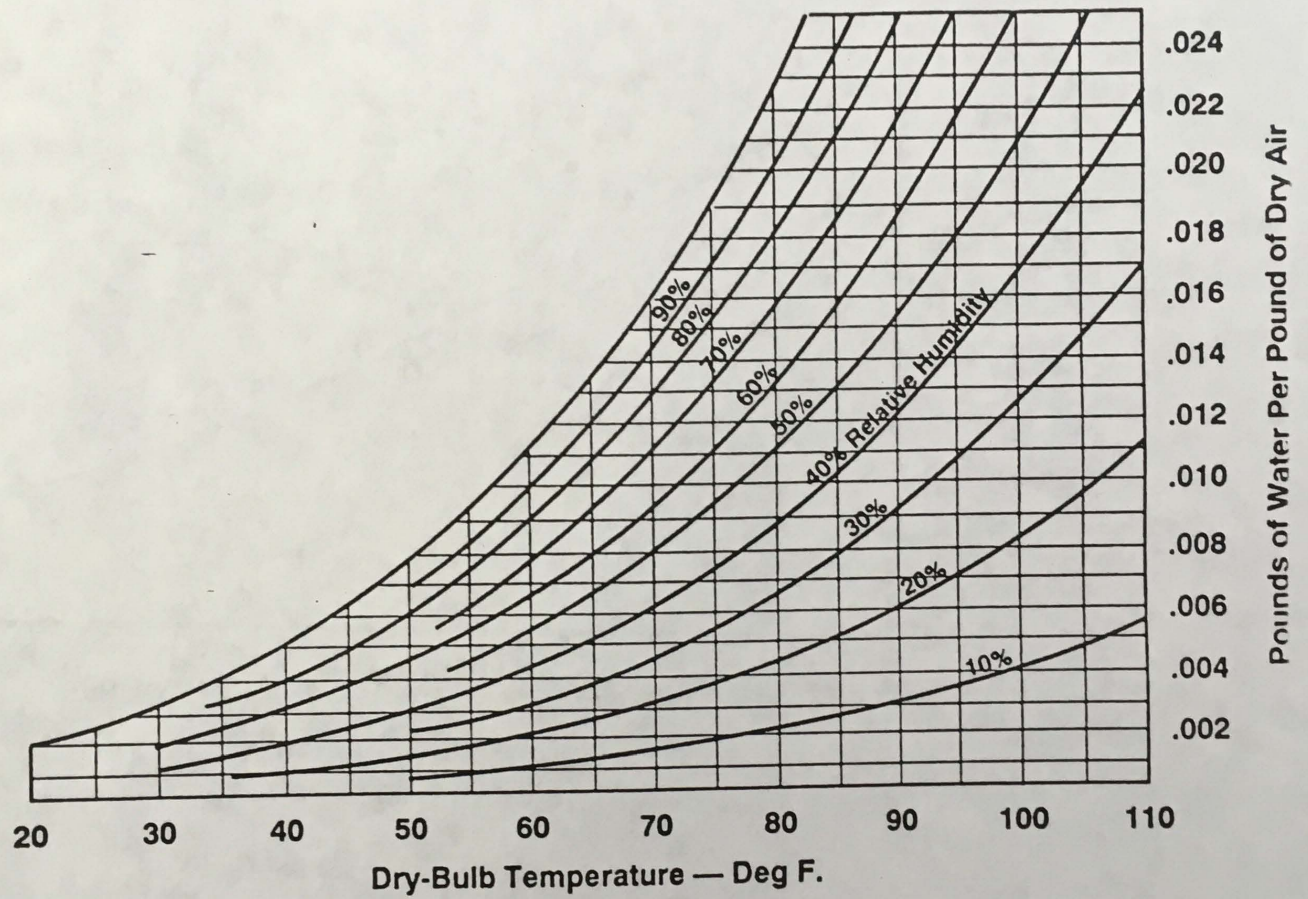
Background
This table is taken directly from AP-42. Conversion of natural gas emission rates is at 1050 Btu/scf. Other fuels are converted at the heating values given in Section 030-001.

Table FHB.12
Fired Heaters and Boilers CO and Hydrocarbon Emission Factors

Fuel and Emission Units	Combustion Unit Size	CO Emission Factors		Hydrocarbon Emission Factors			
				Non-Methane		Methane	
	MBtu/hr	lb/MBtu	g/GJ	lb/MBtu	g/GJ	lb/MBtu	g/GJ
Natural Gas	< 10	0.019	16	0.005	2.2	0.003	1.1
	10 -100	0.033	14	0.003	1.1	0.003	1.2
	> 100	0.038	8.2	0.001	0.6	0.0003	0.1
Distillate Fuel Oil	< 10	0.036	15	0.002	1.0	0.002	0.7
	10-100	0.036	15	0.001	0.6	0.0004	0.2
	> 100	0.036	15	-	-	-	-
Residual Fuel Oil	< 10	0.033	14	0.008	3.2	0.003	1.4
	10-100	0.033	14	0.002	0.8	0.007	2.9
	> 100	0.033	14	0.005	2.2	0.002	0.8

References:
Modified from Perry's Chemical Engineers' Handbook, R.H. Perry, 4th Ed.

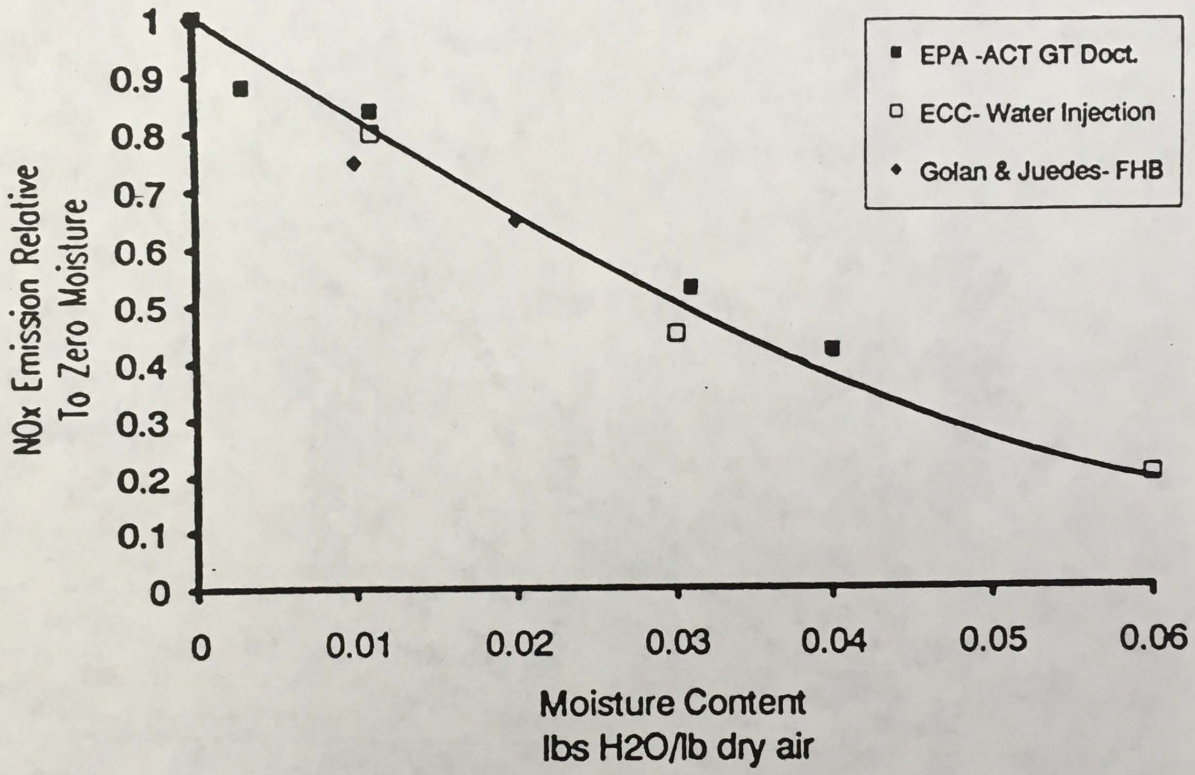
Figure FHB.1
Psychrometric Chart (Barometric pressure 29.92 in. Hg)



ERAE
GRAPHIC DESIGN
3/93-10468-01D

References:
Data for this figure is taken from Alternative Control Technology Document - Stationary Combustion Gas Turbines, EPA July 1991 (Draft); Fired Heater NOx Prediction Tool, L.P. Golan and D.L. Juedes, EE.128E.91, December 1991; and Environmental Control Practice Manual, Exxon Chemical Company

Figure FHB.2
Moisture Content Adjustment



Emission Estimating Guide		Combustion-050-001
Section: Stationary Gas Turbines	**Subject:** Background Information	

Gas turbines are used in refineries and chemical plants to generate electricity, compress fluids, and to driv mechanical equipment. Gas turbines of a wide variety of sizes are used in these applications, with the large turbines having inputs in the range of 300 MBtu/hr. Taken collectively, gas turbines can easily account fc a quarter of a plant's total energy input, and for a significant fraction of the combustion emissions.

Gas turbines are combustion devices and many of the emission considerations are similar to those involved i fired heaters and boilers. The SOx emissions are directly determined by the sulfur content in the fuel. Particulate matter, carbon monoxide, and hydrocarbon emissions are fuel specific. NOx emissions are mor complicated.

NOx Emissions

Nitrogen oxides form in the gas turbine combustor section from the same thermal NOx and fuel nitrogen NO contributing reactions which were discussed in the section on fired heaters and boilers. The amount of NO formed in the combustor flame is 'frozen' and, regardless of temperature reductions that occur downstream c the combustor, is released to the atmosphere from the stack at this level. The primary factors that determin the amount of NOx generated are the combustor design, the types of fuels being burned, ambient condition: operating cycles, and the power output level as a percent of the rated full power output of the turbine.

The level of NOx formation in a gas turbine, and hence the NOx emissions, is unique (by design factors) t each gas turbine model and operating mode. Each gas turbine has a base-rated power level and correspondin NOx level. The combustor design is the most important factor influencing the formation of NOx. Desig factors control equivalence ratios and combustion air introduction to the combustor, which in turn affect th flame temperature, residence time in the flame zone, and the concentration of fuel and oxygen, all of whic strongly influence thermal NOx formation. Inadequate mixing results in localized zones that yield high flam temperatures in which substantial thermal NOx production can take place. The level of NOx emissions varie for different fuels, flame temperature having an influence on thermal NOx formation and fuel nitrogen conte on fuel NOx. The ambient conditions: humidity, temperature, and pressure, also influence the formation c thermal NOx by changing flame temperatures, residence times, and concentration levels in the same manne as was discussed under fired heaters and boilers. Cooling air introduced after combustion is complete does nc affect NOx emissions. A turbine operated in a regenerative cycle produces higher NOx levels due to increase combustor inlet temperatures present in regenerative cycle applications. The power output level of a ga turbine is directly related to the firing temperature which, in turn, is directly related to flame temperatur which, in turn, affects NOx emissions.

The fuels used in gas turbines in refinery and chemical plants include natural gas, low Btu refinery fuels, hig Btu refinery blend gases, and distillate fuels. Some of the gaseous fuels used contain appreciable concentratio of hydrogen or ammonia. The hydrogen will increase the thermal NOx contribution and the ammonia wi increase the fuel NOx contribution.

It is common in refinery and chemical plant applications of gas turbines to install a heat recovery system generate steam from the heat in the exhaust from the gas turbine. This combined operation, in which tl turbine's primary role of generating electricity, driving a compressor or providing mechanical drive supplemented by steam raising, is referred to as cogeneration. In some cogeneration applications, the exhau heat from the gas turbine is not sufficient to produce the desired quantity of steam from the heat recovery stea generator (HRSG), and a supplemental burner, or duct burner, is placed in the exhaust duct between the g turbine and HRSG to increase temperature to sufficient levels. The duct burner adds an additional NC emission to the combined operation.

There are very effective control technologies to reduce the emissions of NOx from gas turbines. Two of thes water or steam injection and selective catalytic reduction with ammonia (SCR), are widely used and will b covered in this section. Another promising control technology, that is still in the developmental stag involves changes to the combustor, similar to the low NOx burners discussed in the section on fired heate and boilers. All but the SCR approach work by modifying the NOx formation conditions in the combusto This modification of combustion conditions also affects the emissions of carbon monoxide and hydrocarbons

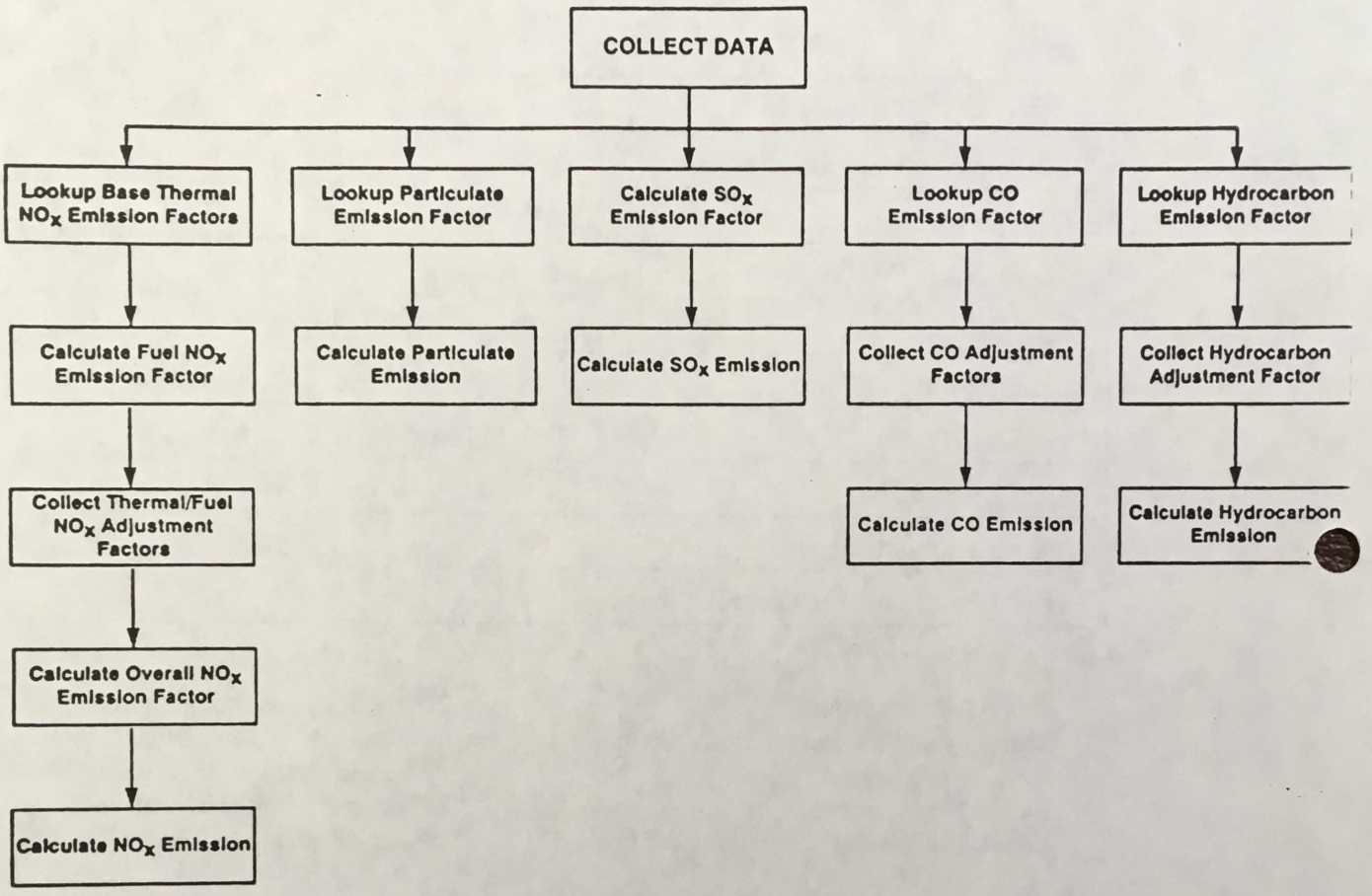
Collecting data for estimating emission factors for stationary gas turbine is similar to that for fired heaters and boilers. Following is a list of data one need and possible sources of information.

Data	Unit	Where
Turbine Manufacturer and Model	N/A	2, 3
Fuel type	N/A	1, 2, 3, 4
Fuel Nitrogen Content	wt. %	6, 7
Fuel Sulfur Content	wt. %	6, 7
Actual Fuel Firing Rate	MBtu/hr.	1, 2, 3, 4, 5
Unit Load Factor	% of full load	2, 3, 5
Temperature at Site	F	9, 10
Relative Humidity at Site	%	9, 10
Post-Combustion NOx Control Tech.	N/A	8

1) Daily furnace report
2) Monthly operating summary
3) Monthly energy conservation report
4) Financial report for fuel cost/allocation
5) Annual production report
6) Environmental engineering
7) Facility laboratory
8) Process or mechanical engineering
9) Local Meteorological stations
10) Almanac

The following page shows a block diagram of steps one needs to take to compete the emission estimation process.

BLOCK DIAGRAM OF STATIONARY GAS TURBINES EMISSION ESTIMATION



NOx Emissions

Developing emission factors for NOx emissions from gas turbines is complicated. In the discussion on NO emissions, several parameters that affect NOx emission were identified: Specific turbine model designs, fue composition, ambient conditions, fuel nitrogen levels, and power load. The method we will use for estimatin the NOx emission factor from gas turbines is as follows:

Step 1 - Determine the base thermal NOx emission factor

Based on the specific turbine by manufacturer and model, look-up in Table GT.1 the bas emission factor for the fuel type used. The base emission factor represents operations a reference temperature and humidity and at the design power load. Table GT.1 contains ga turbine and fuel combinations that are used within Exxon.

Step 2 - Adjusting for moisture content

Adjust the base NOx emission for ambient temperature and moisture content by first usin Figure FHB.1 to determine the weight of water added per weight of dry air, and then usin Table FHB-6 from the section on Fired Heaters and Boilers to determine the NOx adjustmen factor.

Step 3 - Adjusting for fuel hydrogen

If the fuel used is gas and if the gas contains hydrogen, adjust for the thermal NOx contributio due to the hydrogen content of the fuel using Table FHB.2 in the section on Fired Heaters an Boilers.

Step 4 - Adjusting for load factor

Adjust for the effect of power load using the load adjustment factor in Table FHB.7 in th section on Fired Heaters and Boilers.

Step 5 - Calculate the thermal NOx emission factor

Multiply the base emission factor (Step 1) by the adjustment factors from Step 2, 3, and 4. Th results is in lbs of NO2 per MBtu fired.

Thermal NOx Emission Factor = Step 1 x Step 2 x Step 3 x Step 4.

Step 6 - Calculate the fuel NOx emission factor

The contribution of fuel bound nitrogen will be determined using the same approach and tables developed in the Fired Heater and Boiler section. That is, determine the stoichiometric NO2 equivalent of the fuel bound nitrogen and multiply this by the fraction of the fuel nitrogen that is converted to NOx from Table FHB.9 in the section on Fired Heaters and Boilers.

Step 7 - Adjusting for NOx control technology

An adjustment for the NOx reduction from post-combustion NOx emission control technology, usually selective catalytic reduction, will be determined by applying a single factor for NOx reduction obtained from Table FHB.10 in the section on Fired Heaters and Boilers.

Step 8 - Calculate the overall NOx emission factor.

Add the thermal NOx (Step 5) and Fuel Nitrogen NOx (Step 6) and multiply the sum by the post-combustion NOx reduction factor (Step 7).

For cogeneration systems a duct burner is often installed downstream to increase steam generation. An additional adjustment needs to be made for the NOx contribution of this burner. In principle, estimating the additional NOx emission can be done using the methods used in the Fired Heaters and Boilers section. The burner would be treated as a boiler burner operating at the air preheat temperature and flue gas dilution determined from the gas turbine exhaust conditions. The air preheat will increase the NOx level, while the flue gas dilution reduces the NOx level. Usually the net effect is a reduction in NOx across the duct burner. The information to calculate this change in NOx is often not available and a general adjustment of 0.1 lb/MBtu of additional fuel fired through the duct burner is used to approximate the effect of the duct burner.

Particulate Emissions

The particulate emission factor is determined directly from AP-42, Section 3.1.

Step 1 - Based on the fuel type and particulate estimate required, look up the particulate emission factor from Table GT.2.

Step 2 - Calculate the particulate emission by multiplying the particulate emission factor (Step 1) by firing rate in units of MBtu/yr to obtain annual particulate emission.

SOx Emissions

The SOx emission factor is determined directly from the sulfur content of the fuel. A stoichiometric calculation for SO2 is made assuming 100 percent of the feed sulfur is converted to SO2.

Carbon Monoxide and Hydrocarbon Emissions

The uncontrolled carbon monoxide and hydrocarbon emission factors are also based on AP-42, Section 3.1. Adjustments that take into account the change in CO and hydrocarbon emissions due to the effect of water or steam injection for NOx control are also given.

Step 1 - Based on the fuel type, look up the base CO and hydrocarbon emission factors from Table GT.3.

Step 2 - In areas of high humidity, or if water or steam injection is used, lookup the CO and hydrocarbon adjustment factors from Table GT.4. Otherwise the adjustment factor is 1.0.

Step 3 - Multiply the adjustment factor (Step 2) by the base emission factors (Step 1) to obtain final CO and hydrocarbon emission factors.

Step 4 - Calculate the carbon monoxide and hydrocarbon emissions by multiplying the carbon monoxide and hydrocarbon emission factors (Step 3) by the firing rate in units of MBtu/yr to obtain annual carbon monoxide and hydrocarbon emissions.

Scope

This is the base table of NOx emission factors by gas turbine model and fuel used.

References

(1) Alternative Control Technology Document-Stationary Combustion Gas Turbines, EPA-453/R-93-007 Table 4.1, Jan. 1993

(2) NOx Control Applications Guide for Gas Turbines, D.M. O'Dea, EE.18E.92, Feb. 92

Background

This table lists manufacturer estimates for the NOx emission from various models of gas turbines fired with natural gas or distillate fuel.

Table GT.1
Gas Turbine Base NOx Emission Factors

Manufacturer	Model No.	MW	NOx Emissions Factor			
			Natural Gas		Distillate Fuel No. 2	
			lb/MBtu	g/GJ	lb/MBtu	g/GJ
Solar	Saturn	1	.397	171	.551	237
	Centaur	3	.521	224	.658	283
	Centaur "H"	4	.421	181	.588	253
	TAURUS	4	.457	197	.618	266
	MARS T12000	9	0.714	307	0.981	422
GM/Allison	501-KB5	4	.622	267	.849	365
	570-KA	5	.405	174	.669	288
	571-KA	6	.405	174	.669	288
General Electric	LM-1600	13	.577	248	.871	375
	LM-2500	22	.698	300	1.27	546
	LM-5000	33	.742	319	1.34	576
	LM-6000	42	.882	379	1.53	658
	MS5001 P	26	.569	245	.776	334
	MS6001 B	38	.593	255	.981	422
	MS7001 EA	83	.618	266	.838	360
	MS7001 F	123	.718	309	1.02	439
	MS9001 EA	150	.706	304	.864	372
	MS9001 F	212	.706	304	1.00	430
Asea Brown Boveri	GT35	17	1.20	516	1.32	568
	GT10	23	.601	258	.735	316
	GT11N	82	1.56	671	2.06	886
Rolls Royce[a]	AVON	15	0.455	196	N/A	-
Siemens	V84.2	103	.850	366	1.32	568
Westinghouse[a]	W501	101	0.770	331	N/A	-
	W701	128	0.513	221	N/A	-

Note: (a) Emission Factors for Rolls Royce and Westinghouse GT from Reference (2).

Scope
This table contains the particulate emission factors.

References
Compilation of Air Pollutant Emission Factors, AP-42, 4th ed., September 1985.

Background
This table is taken from AP-42, Table 3.1-2. For gas turbines, Exxon Chemical Company assumes tota suspended particulate as PM-10.

Table GT.2
Gas Turbine Total Suspended Particulate (TSP) Emission Factors

Fuel	Total Suspended Particulate Emission Factors	
	lb/MBtu	g/GJ
Natural Gas Fired	0.013	5.7
Distillate Oil Fired	0.036	15

Scope
This table contains the base CO and hydrocarbon emission factors. Adjustment factors when using wate injection can be found in Table GT.4.

References
Compilation of Air Pollutant Emission Factors, AP-42, 4th ed., September 1985.

Background
This table is taken from AP-42, Table 3.1-2.

Table GT.3
Gas Turbine Base CO and Hydrocarbon Emission Factors

Fuel	CO Emission Factors		Hydrocarbon Emission Factor[a]	
	lb/MBtu	g/GJ	lb/MBtu	g/GJ
Natural Gas Fired	0.11	47	0.04	17
Distillate Oil Fired	0.11	47	0.04	17

Note: (a) Non-methane hydrocarbons are assumed to make up 5 to 10% of these totals on the average.

Scope

This table is used to adjust the carbon monoxide (CO) and hydrocarbon emissions for the effect of moistur that is in the combustion air or that is deliberately added as water or steam injection.

References

Alternative Control Technology Document-Stationary Combustion Gas Turbines, EPA, July 1991 (DRAFT

Background

Moisture in the combustion air lowers the flame temperature and results in less complete combustion of th fuel. This leads to increases in the CO and hydrocarbon emissions.

Table GT.4
CO and Hydrocarbon Adjustment Factors
for Water or Steam Injection

Water-to-Fuel Ratio (lb/lb)	0	0.2	0.4	0.6	0.8	1.0
CO Adjustment Factors	1.0	1.0	1.1	1.3	1.6	2.3
Hydrocarbon Adjustment Factors	1.0	1.0	1.0	1.1	1.2	1.4

Stationary reciprocating internal combustion (IC) engines are used in petroleum and petrochemical operation where mechanical work is performed using shaft power. These engines operate on the same principles a automotive engines. The engines produce high emissions of CO, hydrocarbon, and NOx per unit of energ fired and can be responsible for a high fraction of a facility's emissions.

All reciprocating IC engines utilize the same basic process. A combustible fuel-air mixture is compresse between a moveable piston and its surrounding cylinder and head. The mixture then ignites spontaneously o is ignited by an electric discharge. The energy generated by the combustion process drives the pisto downward. The piston's linear motion is converted via a crankshaft to rotary power.

Reciprocating IC engines are primarily classified by the method of ignition and the type of fuel used. In th petroleum and petrochemical industry, the primary fuels for IC engines are natural gas and diesel, depending on the method of ignition.

Two methods of igniting the fuel-air mixture are used in IC engines: spark ignition (SI) and compressio ignition (CI). The ignition method is related to the type of fuel used and the thermodynamic cycle involved. All gasoline or natural gas engines (Otto Cycle) are SI engines. The fuel is usually premixed with air at th intake valve, then ignited in the cylinder by an electrical discharge across a spark plug. All diesel-fue engines (Diesel Cycle) are CI engines. Air is introduced into the cylinder and compressed. High pressu compression raises the air temperature to the ignition temperature of the diesel fuel. The diesel fuel is the injected into the hot air and spontaneous ignition occurs.

The IC engines used in the petroleum industry are typically large bore engines, with multiple cylinders of 8 to 18 inch bore, and 400 to 13,000 hp (300 to 9,700 kW) output. These engines tend to be fueled with natura gas and are used in applications requiring continuous operations, such as electric power generation, oil and ga pipeline transmission, oil and gas production and refinery and chemical plant drives. Diesel engines, with power ratings of about 350 hp (260 kW), are used extensively in on-land and off-shore drilling.

Parameters Affecting Emissions

The above discussion suggested several parameters that might influence the emissions. These include: the type of fuel, the ignition method, and the size of the engine. In addition, as in the emissions from fired heater and boilers, parameters that can affect the emission of a particular combustion pollutant, for example, the sulfur and nitrogen content of the fuel, the ambient temperature and moisture content, and the ratio of fuel to oxidan also need to be considered.

The estimates for NOx, carbon monoxide and hydrocarbons are interrelated and depend on the relative amount of fuel and oxidant. This concentration ratio is expressed in different ways: equivalence ratio or air to fuel ratio. In this discussion, the air to fuel ratio, A/F, expressed in weight of air to weight of fuel, will be used. Normal operation of the IC engine differs among manufacturers and can be at an A/F slightly lower (fuel-r combustion or rich-burn) or slightly higher (fuel-lean combustion or lean-burn) than stoichiometric.

Maximum temperatures occur when the A/F is just above stoichiometric. Since the formation rate of NOx increases with increases in combustion temperature, maximum NOx occurs when the A/F is slightly above stoichiometric. In any engine, as the A/F increases from stoichiometric (becomes more fuel-lean), NOx formation first increases with the presence of additional combustion oxygen, then steadily decreases as the A/F increases further beyond stoichiometric.

Emissions of CO and hydrocarbon increase slightly at fuel rich A/F's due to the lack of oxygen to fully oxidize the carbon. As the A/F is increased toward fuel-lean conditions, excess oxygen is available and CO emissions decrease as essentially all carbon species are oxidized to CO2. At fuel-lean A/F's, hydrocarbon emissions increase slightly as excess oxygen cools combustion temperatures and inhibits complete combustion.

As discussed earlier, combustion is initiated by the injection of fuel oil in CI engines or by a spark in SI engines. By delaying, or retarding , the timing of ignition, the combustion process occurs later in the power stroke when the piston is in downward travel. Ignition retard, therefore, effectively increases the combustion chamber volume, which reduces pressure in the cylinder and lowers combustion temperatures. These lower combustion temperatures, in turn, result in lower NOx emissions. Emissions of CO and hydrocarbon are not significantly affected by timing retard. except in extreme cases where misfiring occurs. While timing retard lowers NOx levels significantly, the lower combustion pressures result in reduced cycle efficiency and increased engine fuel consumption.

Ambient temperature and moisture content affect the NOx emission level. Temperature changes the mass of air that is introduced in each cycle and affects the NOx level by changing the A/F ratio. A 40°F increase in ambient temperature can mean a 12% decrease in the A/F ratio, and with it a drop in NOx. Humidity has an additional effect on NOx in that high moisture levels reduce the peak temperatures within the engine cylinders, decreasing NOx emissions by up to 25%. The design A/F varies for different IC engines, so engines respond differently to changes in atmospheric conditions.

Fuel composition also plays a role in determining the NOx emissions. As with the fired heaters and boilers, the effect of fuel hydrogen content on the formation of thermal NOx and of fuel-bound nitrogen on fuel NOx must be taken into account.

There are additional parameters that affect NOx emissions, including: combustion chamber and injection valve design, engine combustion cycle (two- or four-stroke cycle), and the effect of engine load. There is insufficient data to predict the effect of these parameters on the emissions and these parameters will not be considered in this estimating procedure.

The Effect of NOx Control Techniques on Emissions

Earlier we showed that the adjustment to the A/F ratio changed the relative amounts of fuel and oxidant. This adjustment can provide an average NOx reduction of 25%.

Adjustment of the ignition timing in the power cycle affects the pressure and temperatures in the compressio chamber. Advancing the timing so that ignition occurs earlier in the power cycle results in peak combustio when the piston is near the top of the cylinder, when the combustion volume is at a minimum. This timin adjustment results in maximum pressures and temperatures and increases NOx emissions. Retarding th ignition timing causes the combustion process to occur later in the power stroke, reducing operating pressure and temperatures, thereby reducing NOx formation. Generally, a 2 degree retard reduces NOx by about 20% and a 4 degree retard by 35%.

Combining the A/F ratio adjustment with the ignition retard reduces NOx by 40%.

The pre-stratified charge (PSC) control system injects air into the intake manifold in a layered, or stratified charge arrangement. This stratified charge allows a leaner A/F to be burned without increasing the possibility of misfire due to lean flammability limits. The PSC system is used as an add-on control device for rich-burn naturally aspirated or turbocharged, carbureted, 4-cycle engines. An average NOx reduction of 84% is claimed.

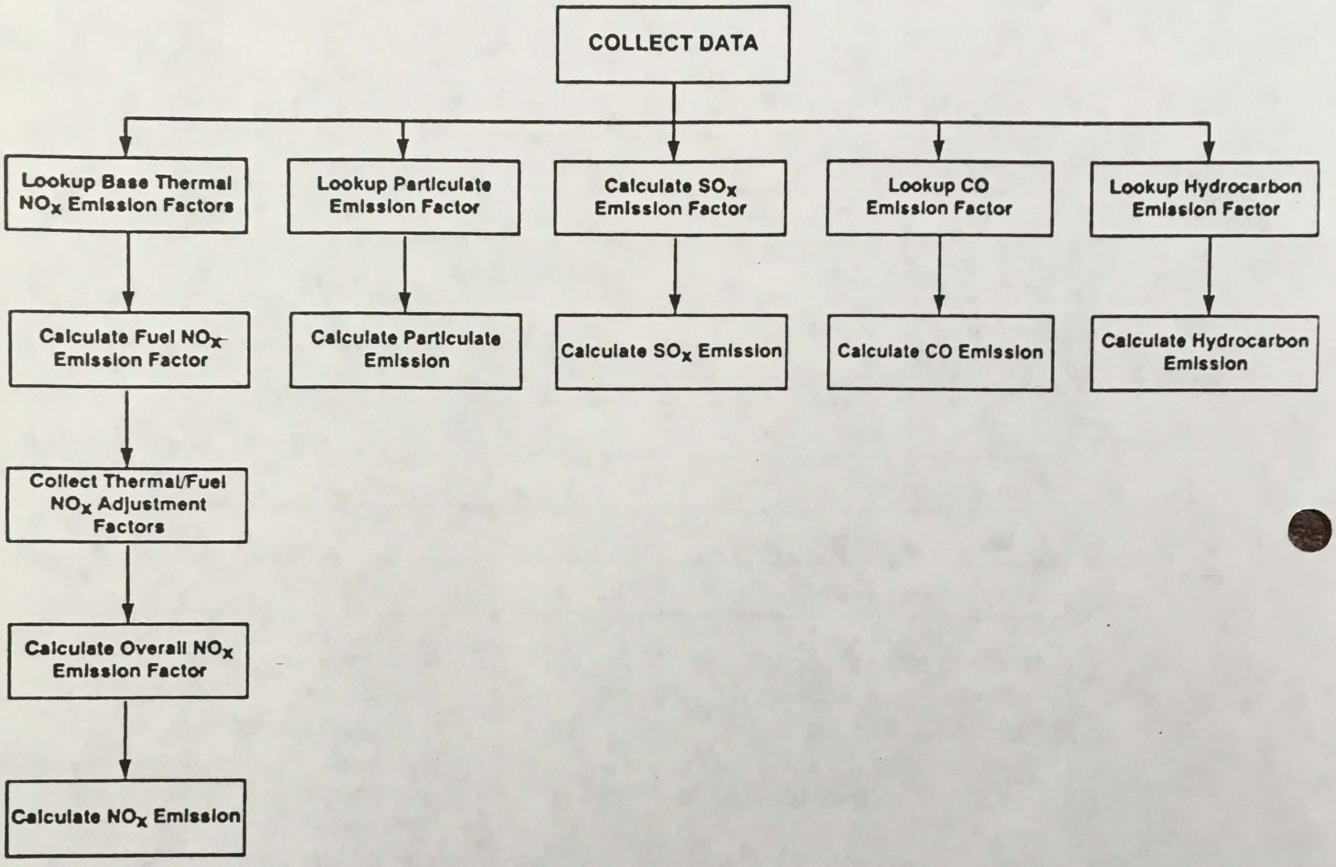
Collecting data for estimating emission factors for stationary internal combustion engines is also similar to that for fired heaters and boilers. Following is a list of data one need and possible sources of information.

Data	Unit	Where
Engine Type	N/A	2, 3
Engine Size	hp	1, 2, 3
Fuel type	N/A	1, 2, 3, 4
Fuel Nitrogen Content	wt. %	6, 7
Fuel Sulfur Content	wt. %	6, 7
Actual Fuel Firing Rate	MBtu/hr.	1, 2, 3, 4, 5
Unit Load Factor	% of full load	2, 3, 5
Temperature at Site	F	9, 10
Relative Humidity at Site	%	9, 10
Post-Combustion NOx Control Tech.	N/A	8

1) Daily furnace report
2) Monthly operating summary
3) Monthly energy conservation report
4) Financial report for fuel cost/allocation
5) Annual production report
6) Environmental engineering
7) Facility laboratory
8) Process or mechanical engineering
9) Local Meteorological stations
10) Almanac

The following page shows a block diagram of steps one needs to take to compete the emission estimation process.

BLOCK DIAGRAM OF STATIONARY IC ENGINES EMISSION ESTIMATION



NOx Emissions

Specific IC engine model designs, fuel composition, humidity and fuel nitrogen have been identified as parameters affecting NOx emissions from internal combustion engines. The method we will use for estimating the NOx emission factor from internal combustion engines is as follows:

Step 1 - Based on the specific engine by type of fuel injection and size, lookup in Table ICE.1 the base emission factor. The base emission factor represents operations at reference temperature and humidity and at the design power load. Table ICE.1 contains several internal combustion engine types that are used within Exxon.

Step 2 - Adjust the base NOx emission for humidity using Table FHB.6 from the section on Fired Heaters and Boilers.

Step 3 - If the fuel used is gas and if the gas contains hydrogen, adjust for the thermal NOx contribution due to the hydrogen content of the fuel using Table FHB.2 in the section on Fired Heaters and Boilers.

Step 4 - Determine the thermal NOx contribution by multiplying the base emission factor (Step 1) by the adjustment factors in Steps 2 and 3.

Step 5 - The contribution of fuel bound nitrogen is determined using the same approach and tables developed in the Fired Heater and Boiler section. That is, determine the stoichiometric NO2 equivalent of the fuel bound nitrogen and multiply this by the fraction of the fuel nitrogen that is converted to NOx from Table FHB.9 in the section on Fired Heaters and Boilers.

Step 6 - An adjustment for the installation of NOx emission control technology, usually timing adjustment and air-to-fuel ratio adjustment, is determined from Table ICE.2.

Step 7 - Calculate the overall NOx emission factor.

Add the thermal NOx emission contribution (Step 4) and the fuel nitrogen NOx contribution (Step 5) and multiply the sum by the NOx emission control technology factor (Step 6).

Step 8 - Calculate the overall NOx emission

Multiply overall NOx emission factor (Step 7) by the firing rate in units of MBtu/yr to obtain annual NOx emission.

Particulate Emissions

The particulate emission factors are determined directly from AP-42.

Step 1 - Based on the fuel type, lookup the base particulate emission factor from Table ICE.3.

Step 2 - Calculate the particulate emission by multiplying the particulate emission factor (Step 1) by firin rate in units of MBtu/yr to obtain annual particulate emission.

Carbon Monoxide and Hydrocarbon Emissions

The uncontrolled carbon monoxide and hydrocarbon emission factors are based on AP-42, Section 3.4.

Step 1 - Based on the fuel type, lookup the CO and hydrocarbon emission factors from Table ICE.4.

Step 2 - Calculate the carbon monoxide and hydrocarbon emissions by multiplying the carbon monoxide ar hydrocarbon emission factors (Step 1) by firing rate in units of MBtu/yr to obtain annual carbc monoxide and hydrocarbon emissions.

SOx Emissions

The SOx emission factor is determined directly from the sulfur content of the fuel. A stoichiometric calculatic for SO2 is made assuming 100 percent of the feed sulfur is converted to SO2.

Emission Estimating Guide	Combustion-060-003
Section: Stationary Internal Combustion Engines	**Subject: Table ICE.1** IC Engine Base NOx Emission Factor

Scope
This is the base table of NOx emission factors by stationary internal combustion engine (ICE) model and fue used.

References
Alternative Control Techniques Document-Control of NOx Emissions From Stationary Internal Combustion Engines, EPA, August 1992 (DRAFT)

Background
This table lists estimates for the NOx emission for uncontrolled stationary internal combustion engines by type of fuel injection and engine size. In Table ICE.1, the fuel used for spark ignited engines is natural gas and for compression ignition engines (diesels) is distillate fuel oil.

Table ICE.1
IC Engine Base NOx Emission Factors

Engine Type	Fuel Type	Engine Size	NOx Emission Factors		
		hp	g/hp-Hr	g/GJ	lbs/MBtu
Spark Ignited	Nat. Gas	<400	12.5	1,460	3.40
		401-1,200	17.2	2,140	4.97
		1,201-4,000	18.8	2,450	5.70
		>4,000	17.0	2,400	5.59
Compression Ignited	Dist. Oil	<400	11.5	1,570	3.65
		401-1,200	12.8	1,650	3.84
		1,201-4,000	11.2	1,600	3.73
		>4,000	12.0	1,810	4.21

Scope

This table is used to adjust the ICE NOx emission factors for the effect of NOx reduction control technologies that may be installed. The prevalent control technologies are retarding the ignition timing and adjusting the air/fuel ratio.

References

Alternative Control Techniques Document-Control of NOx Emissions From Stationary Internal Combustion Engines, EPA, August 1992 (DRAFT)

Letter to Mr. Robert Snyder, Midwest Research Institute, from P.D. Eichamer, 92BCPR2217, June 24, 1992.

Background

This table lists estimates for the NOx emission adjustment factors for stationary internal combustion engines provided by the installation of NOx control technologies.

Table ICE.2
IC Engine NOx Control Technology Adjustment Factors

Technology	Applicable To Engine Type	Adjustment Factors
Ignition Timing	any rich-burn engine	0.65
Air-to-Fuel Ratio Tuning	any rich-burn engine	0.75
Combination IT & A/F	any rich-burn engine	0.60
Pre-Stratified Charge	rich burn, naturally aspirated or turbo charged, carbureted, 4-cycle engine	0.16

Scope
This table contains the particulate emission factors.

References
Compilation of Air Pollutant Emission Factors, AP-42, 4th ed., September 1985, Table 3.2-1.

Background
The diesel engine particulate emission factor is taken directly from AP-42. No data is available for natural gas engines. Therefore, the emission factor from the Fire Heaters and Boilers section is used for natural gas engines.

Table ICE.3
IC Engine Particulate Emission Factors

Fuel	Particulate Emission Factors		
	g/hp hr	lb/MBtu	g/GJ
Diesel	1.1	0.34	148
Natural Gas	-	0.005	2.0

Scope
This table contains the CO and hydrocarbon emission factors for large-bore diesel fired and dual fuel (mixtur of diesel fuel and natural gas) engines.

References
Compilation of Air Pollutant Emission Factors AP-42, 4th ed., September 1985, Table 3.4-1.
Conversion from the values in AP-42 is based on a diesel fuel consumption of 7,000 Btu/hp · hr (9.9 MJ/kW · hr)

Background
This table is taken from AP-42.

Table ICE.4
IC Engine CO and Hydrocarbon Emission Factors

Fuel	CO Emission Factors			Hydrocarbon Emission Factors					
				Methane			Non-Methane		
	g/hp hr	lb/MBtu	g/GJ	g/hp hr	lb/MBtu	g/GJ	g/hp hr	lb/MBtu	g/GJ
Diesel	2.9	0.91	391	0.03	0.009	3.9	0.29	.091	39
Dual Fuel	2.7	-	-	2.1	-	-	0.70	-	-

Emission Estimating Guide		Combustion-070-001
Section: Flares	**Subject:** Background	

Flaring is a high temperature oxidation process used to burn the combustible components of waste gases from petroleum refineries and chemical plants. These waste streams can result from continuous venting operations, purges from periodic equipment preparation, and pressure relief of process vessels under emergency conditions. Often a single flare system provides all of these capabilities. As such, flaring provides a capability for both the disposal of wastes and the safe operation of the facility during emergencies.

The waste gases to be flared are usually piped to a remote location of the facility where the combustion takes place in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete destruction of the combustible components.

Flares are generally categorized in several ways: 1) by the height of the flare tip (e.g., ground level or elevated), 2) by design (e.g., open-pipe, cascade-flow, or burning-pit), and 3) by the method of enhancing mixing at the flare tip (e.g., steam assisted, air assisted, or non-assisted).

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Flare Emission Factors

The flare emission factors given here are for continuous flaring, for example during flaring of vent gases. They are not applicable to upset conditions.

It is common to see references to greater than 98% destruction of VOCs in flares. As used in flare terminology, destruction of VOCs is the complete combustion of VOCs into CO2 and water. At a 98% destruction, emission estimates from AP-42 suggest that approximately 1.5% of the carbon is converted only to CO and that 0.5% remains as unburned hydrocarbon.

Emission estimates for flares will be based on data from AP-42 and from a recent Santa Barbara County, California study on the Santa Ynez on-shore facilities. Table FL.1 shows the emission factors that will be used for the various flare types and designs. Factors are given for thermal NOx, CO, particulates, and hydrocarbons.

The emissions of SOx, additional NOx from flaring nitrogen containing gases, and toxic species require special calculation.

Flare SOx emissions should be calculated based on the level of sulfur in the flare gas. SOx emissions are calculated stoichiometrically assuming all sulfur in the fuel is converted to SO2.

Flare gases which contain fixed nitrogen molecules, for example, ammonia, create more NOx emissions than flare gases without fixed nitrogen. The fuel nitrogen contribution will be determined by calculating stoichiometrically the NO2 that can be formed when all nitrogen in the fuel is converted to NOx. This calculation is then multiplied by the fraction of fuel nitrogen that is converted to NOx obtained from Table FHB.9 in the fired heater and boiler section.

The limited data on toxic emissions produced by flares suggests that the gaseous toxic content of hydrocarbon-based flare gas is approximately 0.001 lb/MBtu of flare gross heat release. The primary components of these gaseous toxic emissions are the aromatics benzene, toluene, and xylenes. (Reference: S.W. Sterner, Flare Study - Phase I Report, Santa Barbara County Air Pollution Control District, July 1991). If speciation of these toxic emission is required, contact ER&E.

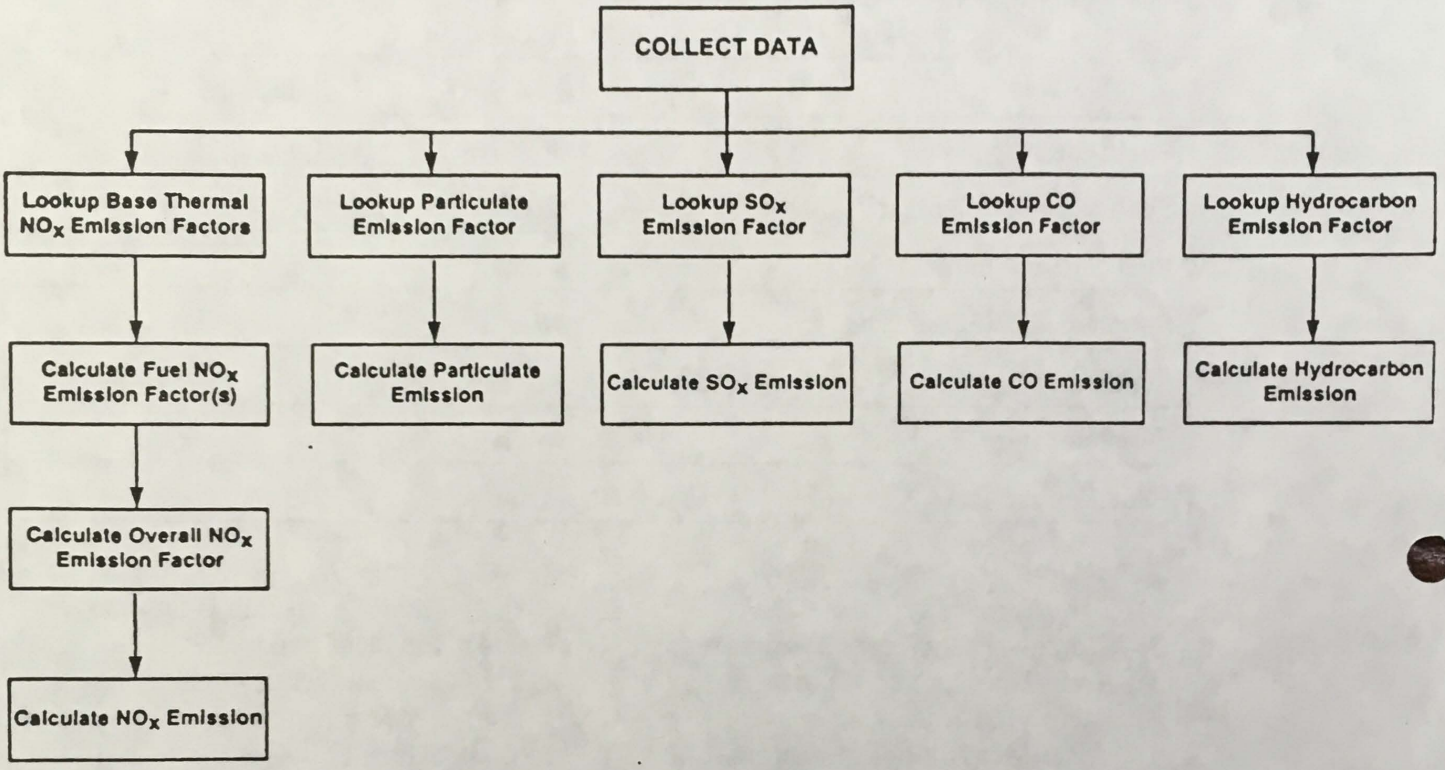
Collecting data for estimating flare emissions can be tricky, because flares are not usually in continuou operation. Following is a list of data one need and possible sources of information.

Data	Unit	Where
Flare type	N/A	11, 2, 3
Fuel type	N/A	11, 1, 2, 3, 4
Fuel Nitrogen Content	wt. %	6, 7
Fuel Sulfur Content	wt. %	6, 7
Supplementary Fuel type	N/A	11, 2, 3
Supplementary Fuel Nitrogen Content	wt. %	6, 7
Supplementary Fuel Sulfur Content	wt. %	6, 7
Heat Release Rate	MBtu/hr.	11

1) Daily furnace reports
2) Monthly operating summary
3) Monthly energy conservation report
4) Financial report for fuel cost/allocation
5) Annual production report
6) Environmental engineering
7) Facility laboratory
8) Process or mechanical engineering
9) Local Meteorological stations
10) Almanac
11) Upset and spill incident report

The following block diagram shows the steps one needs to take to compete the emission estimation process.

BLOCK DIAGRAM OF FLARE EMISSION ESTIMATION



NOx Emissions

Step 1 - Based on the flare type and heat release rate, the emission factor contributed for each of th pollutants is determined from Table FL.1. Note that the flare gas composition is not used fo this initial emission determination. The NOx emission factor determined in this manner is onl the thermal NOx contribution of the waste gas.

Step 2 - The contribution of fuel nitrogen to the NOx emission factor is determined using the metho discussed in the Fired Heater and Boiler section. This involves first making a stoichiometri calculation to convert all of the fuel nitrogen to NO2 and then adjusting this fuel nitroge contribution by the fraction of NOx that is converted to fuel nitrogen using Table FHB.9 in th Fired Heater and Boiler section.

Step 3 - The flare gas contribution to the NOx emission factor is then obtained by adding the therma NOx and the fuel nitrogen NOx contributions.

Step 4 - The overall emission is next determined by multiplying the flare gas NOx emission factor by th flare heat release rate.

Scope

This table contains the base emission factors for open-pipe and cascade flow flares. It is applicable to both elevated and ground flares.

References

Methods to Eliminate and Mitigate Flare Emissions at Oil and Gas Processing Facilities, S.W. Sterner, 85th Annual Meeting, Air & Waste Management Association, June 21-26, 1992.
AP-42 Emission Factors, Section 11.5 Industrial Flares, U.S.E.P.A., September, 1991

Background

This table lists emission estimates from flaring operations. The emission estimates in this table are taken from AP-42 and from the Sterner paper reporting a flaring study conducted by the Santa Barbara County Air Pollution Control District in July 1991, partly in response to questions surrounding emissions from the Exxon Santa Ynez project. The Santa Barbara study used a combination of flare emission estimates from AP-42, Sections 1.4 and 9.1, and from the South Coast Air Quality Management District.

The emission estimates in the table are only valid for fuels containing no nitrogen species. The fuel bound nitrogen contribution to NOx emissions is made through fuel nitrogen NOx emission factors described in the text adjustments.

(Continued on Next Page)

Table FL.1
Flare Emission Factors

Flare Type	lb/MBtu Flare Event Heat Release (High Heating Value, HHV)				Comments and Reference Source
	NOx(a)	CO	PM10	HC[b]	
OPEN FLARES [c]					
Steam or Air Assisted	0.068	0.37	0.0202	0.14	PM10 factor from correspondence with SCAQMD reported in Flare Study - Phase I Report, Santa Barbara Co. APCD Study, July 1991, Appendix A. NOx, CO and VOC factors from AP-42.
CASCADE FLOW CONTROL FLARES (CFCs)					
Thermal Oxidizers, CFC Ground Flares	Heat Release Rate				The factors presented here are AP-42, Section 1.4, Table 1 factors converted from lb/Mscf to lb/MBtu based on 1050 Btu/scf gas heating value.
	Less than 10 MBtu/hr				
	0.0952	0.0190	0.0048	0.0051	
	10 to 100 MBtu/hr				
	0.133	0.0333	0.0048	0.0027	
	Greater than 100 MBtu/hr				
	0.524	0.0381	0.0048	0.0013	

Note(s): (a) These NOx factors are only valid for fuels containing no nitrogen fuel species. If nitrogen fuel species are present in the flare gas, fuel NOx emissions in addition to the values calculated by the above NOx factors need to be added (see text).
(b) Hydrocarbon is total hydrocarbon (THC)
(c) Use the open flare emission factors for elevated flares of either the open pipe design or special burner type design.

Mobile combustion sources usually refer to vehicles that operate on the highways. They are different frc other combustion sources that have been discussed so far in that their operating conditions are not stable. T engine of a mobile source is expected to be started and stopped repeatedly within relatively short periods time and in variable climates and traffic conditions. Due to the large number of vehicles being operated the roads, their emissions contribute significantly to the overall emissions from combustion sources. Therefor mobile emissions are often listed in emission inventories.

Vehicle emissions are known to vary with ambient temperature, humidity, operating speed, cold and hot sta use of air conditioning and carrying of an extra load. In the past several decades, vehicle design has go through dramatic changes in terms of emission reduction. Vehicles from different countries will have differe emissions because of differences in regulations. For example, catalytic converters have been required vehicles in the U.S. for CO and hydrocarbon control for many years. They are only beginning to be require in some European countries.

Vehicles found in an industrial site can usually be categorized in four groups: light duty gasoline power vehicles (< 12 passengers), trucks (< 6,000 lb GVW and 6,000 to 8,500 lb GVW), heavy duty diesel power vehicles (> 8,500 lb GVW).

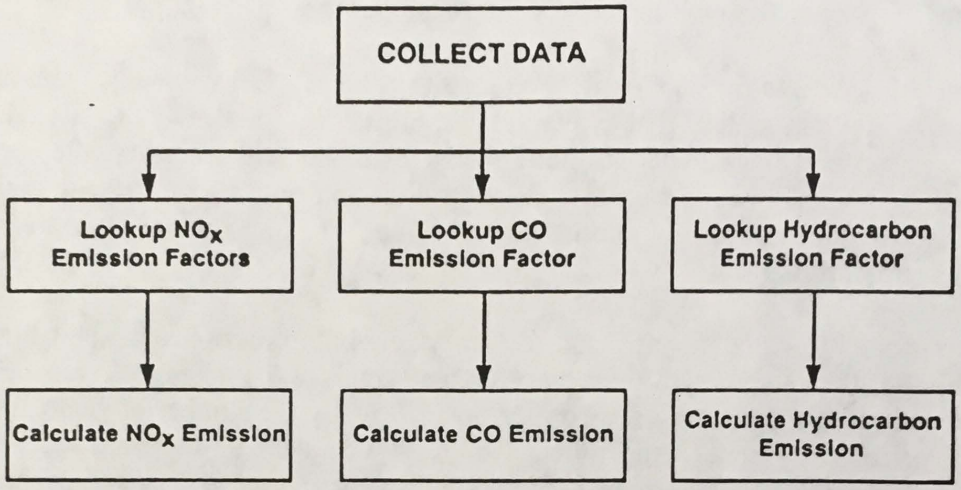
With the implementation of vehicle inspections, a wealth of data has been collected in the U.S. to date. Onl U.S. data will be presented in this Guide. User is advised to use local emission factors, when available, whe estimating emissions for mobile sources in other countries.

Volume II of AP-42 is devoted entirely to mobile sources. Emission adjustment factors have been establishe for many of the parameters that effect vehicle emissions. However, to list all of the factors is beyond th guidance purpose of this Guide. If more precise estimates are necessary, the user is directed to obtain a cop of AP-42, Volume II which provides detailed direction on how to estimate emissions from mobile sources ER&E also has the expertise to provide such service. The pollutants of concern from mobile sources are NOx CO and hydrocarbons.

The data needed to calculate emission factors for mobile sources are perhaps the easiest to obtain because, i all likelihood, there is no system in place to keep track of the mileage driven. So, the person responsible fo this task may start a program of his or her own. Usually the number of vehicles on a site is small enough tha one can periodically record the mileage of each vehicle. If there are mechanics on site responsible fo maintainence of the vehicles, their help may be invaluable. The financial department may have an inventor of the vehicles.

Data	Unit	Where
Vehicle Type	N/A	Inventory
Year Make of Vehicle	N/A	
Mileage driven	mi	record from each vehicle

BLOCK DIAGRAM OF MOBILE SOURCES EMISSION ESTIMATION



EPA/E GRAPHIC DESIGN 3/93-10499-05D

NOx Emissions

Volume II of AP-42 provides NOx emission factors and adjustment factors for mobile sources. Only the ba NOx emission factors as a function of year make of vehicle are shown in this section.

Step 1 - Based on type and year make of vehicle, lookup NOx emission factor from Table MS.1.

Step 2 - Multiply NOx emission factor by the mileage driven per year to obtain annual NOx emissio

Carbon Monoxide and Hydrocarbon Emissions

Volume II of AP-42 provides CO and hydrocarbon emission factors for mobile sources. Only the base CO a hydrocarbon emission factors as a function of year and make of vehicle are shown in this guide.

Step 1 - Based on type and year make of vehicle, lookup CO and hydrocarbon emission factors fro Table MS.2.

Step 2 - Multiply CO and hydrocarbon emission factors by the mileage driven per year to obtain annu CO and hydrocarbon emissions.

Scope
This table contains representative NOx emission factors for mobile sources.

References
Compilation of Air Pollutant Emission Factors AP-42, Volume II, September 1985.

Background
Volume II of AP-42 provides NOx emission factors for many year make of vehicles. The values shown ir Table MS.1 are averages of those emission factors.

Table MS.1
Mobile Sources NOx Emission Factors

Type of Vehicle	Year Make of Vehicle	NOx Emission Factors g/mile
Light Duty Gasoline Powered Vehicles (< 12 passengers)	Pre - 1970	3.9
	1971 - 1975	3.9
	1976 - 1980	3.7
	1981 - 1985	2.6
	1986 - 1990+	1.8
Light Duty Gasoline Powered Trucks (< 6,000 lb GVW)	Pre - 1970	4.0
	1971 - 1975	4.1
	1976 - 1980	4.1
	1981 - 1985	3.8
	1986 - 1990+	2.2
Light Duty Gasoline Powered Trucks (6,000 - 8,500 lb GVW)	Pre - 1970	5.4
	1971 - 1975	6.0
	1976 - 1980	4.9
	1981 - 1985	3.8
	1986 - 1990+	2.2
Heavy Duty Diesel Powered Vehicles (> 8,500 lb GVW)	Pre - 1970	22.5
	1971 - 1975	25.1
	1976 - 1980	23.9
	1981 - 1985	19.1
	1986 - 1990+	12.9

Scope
This table contains representative CO and Hydrocarbon emission factors for mobile sources.

References
Compilation of Air Pollutant Emission Factors AP-42, Volume II, September 1985.

Background
Volume II of AP-42 provides CO and hydrocarbon emission factors for many year make of vehicles. Th values shown in Table MS.2 are averages of those emission factors.

Table MS.2
Mobile Sources CO and Hydrocarbon Emission Factors

Type of Vehicle	Year Make of Vehicle	CO Emission Factors	Hydrocarbon Emission Factors
		g/mile	g/mile
Light Duty Gasoline Powered Vehicles (< 12 passengers)	Pre - 1970	95.1	8.5
	1971 - 1975	77.0	6.3
	1976 - 1980	58.3	5.4
	1981 - 1985	31.8	2.3
	1986 - 1990+	20.0	1.5
Light Duty Gasoline Powered Trucks (< 6,000 lb GVW)	Pre - 1970	101.5	8.7
	1971 - 1975	79.8	6.6
	1976 - 1980	74.9	6.8
	1981 - 1985	38.6	4.1
	1986 - 1990+	21.5	1.9
Light Duty Gasoline Powered Trucks (6,000 - 8,500 lb GVW)	Pre - 1970	125.1	12.1
	1971 - 1975	95.0	9.4
	1976 - 1980	85.2	7.9
	1981 - 1985	39.2	4.2
	1986 - 1990+	21.4	1.9
Heavy Duty Diesel Powered Vehicles (> 8,500 lb GVW)	Pre - 1970	12.1	4.2
	1971 - 1975	13.5	4.7
	1976 - 1980	13.0	4.7
	1981 - 1985	10.6	3.9
	1986 - 1990+	9.8	2.7

Problem: determine NOx emission factor for an MEK furnace operating at 15% excess air with th following fuel gas composition.

Component	Mole Percent
C_1	25
C_2	25
H_2	50

Comments On This Problem: Like many real-world situations, there is no easy classification for the fuel use in this problem. The fuel is clearly not natural gas. It is a refinery gas, but an RFG that bears littl resemblance to the RFG composition used to develop the base NOx emission factor in Table FHB.1. The use has to make a choice to assume a natural gas and correct for added H_2 content, or to assume a RFG and correc for the incremental H_2 content.

Step 1 - Collect the fuel properties and operating conditions

Fuel H2 Content (%):	50
Combustion Air Preheat Temperature (°F):	no preheat
Average Relative Humidity at Site (%):	40[a]
Unit Load Factor (%):	100%[a]
Average Temperature at Site (°F):	60[a]
Burner Intensity Classification:	High ____ or Normal X[a]
Fuel Nitrogen Content (wt.%):	0
Fuel Firing Rate (MBtu/hr):	N/A
Fuel HHV (appropriate units):	not needed
NOx Reduction Technologies Used:	none[a]

Note: (a) These values are assumed for lack of other data

Step 2-9 Determine Thermal NOx Emission Factor

Basis: Assume RFG as fuel type and then adjust for incremental H_2 content.

Base NOx emission factor (Table FHB.1) = 0.17 lb/MBtu

Type of Adjustment Factor	References	Adjustment Factor	Comment
H2 content adjustment	Table FHB.2	1.13	assumes 25% H_2 increment
At-the-source NOx reduction tech.	Table FHB.3	1.0	none assumed
Flue gas recirculation	Table FHB.4	1.0	none assumed
Air preheat	Table FHB.5	1.0	no preheat at 60°F, interpolate
Moisture content	Fig. FGH.1 & 2 Table FHB.6	1.0	
Load factor	Table FHB.7	1.0	no info., assume 100%
Burner intensity	Table FHB.8	1.0	

Thermal NOx Emission Factor = 0.17 lb/MBtu x 1.13 x 1.0

= **0.19 lb/MBtu**

Step 10-12 Determine Fuel NOx Emission Factor

There is no nitrogen in fuel, therefore

Fuel NOx Emission Factor = **0 lb/MBtu**

Step 13-14 Determine Overall NOx Emission Factor

Post combustion NOx adjustment factor from Table FGH.13 = 1.0 since no post-combustion NOx control is used.

Overall NOx Emission Factor = (0.19 lb/MBtu + 0 lb/MBtu) x 1.0

= **0.19 lb/MBtu**

Comparison with Actual Case

In a similar case performed for Exxon's Bayway Chemical Plant, the NOx emission estimate was **0.15 lb/MBtu.**

References

NOx Emission Estimate MEK Furnace, C.B. Barbre, 87.ECS 1-115, April 7, 1987

Step 2-9 Determine Thermal NOx Emission Factor

Basis: Assume natural gas as fuel type and adjust for total H_2 content.

Base NOx emission factor (Table FHB.1) = 0.13 lb/MBtu

Type of Adjustment Factor	References	Adjustment Factor	Comment
H2 content adjustment	Table FHB.2	1.46	50% H_2 content
At-the-source NOx reduction tech.	Table FHB.3	1.0	none assumed
Flue gas recirculation	Table FHB.4	1.0	none assumed
Air preheat	Table FHB.5	1.0	no preheat at 60°F, interpolate
Moisture content	Fig. FGH.1 & 2 Table FHB.6	1.0	
Load factor	Table FHB.7	1.0	no info., assume 100%
Burner intensity	Table FHB.8	1.0	

Thermal NOx Emission Factor = 0.13 lb/MBtu x 1.46 x 1.0

= **0.19 lb/MBtu**

Step 10-12 Determine Fuel NOx Emission Factor

There is no nitrogen in fuel, therefore

Fuel NOx Emission Factor = **0 lb/MBtu**

Step 13-14 Determine Overall NOx Emission Factor

Post combustion NOx adjustment factor from Table FGH.13 = 1.0 since no post-combustion NOx control is used.

Overall NOx Emission Factor = (0.19 lb/MBtu + 0 lb/MBtu) x 1.0

= **0.19 lb/MBtu**

Comparison with Actual Case

In a similar case performed for Exxon's Bayway Chemical Plant, the NOx emission estimate was **0.15 lb/MBtu.**

References

NOx Emission Estimate MEK Furnace, C.B. Barbre, 87.ECS 1-115, April 7, 1987

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Problem: 100% conversion of fuel sulfur to SO_2

Given: - a low Btu gas (LBG) with the following properties

Component	Mol Percent	
C_1	0.8	
CO	23.9	
CO_2	5.6	
H_2	14.7	
N_2	51.4	
H_20	3.6	
H_2S	50.0	(vppm)
COS	380.0	(vppm)
CH_3SH	60.0	(vppm)

- Furnace operating at 15% excess air
- Molecular Weight = 26.6 lb/lb mol
- Fuel HHV = 133 Btu/scf

100% conversion of fuel sulfur to SO_2

Total fuel sulfur = (50 + 380 + 60) vppm = 490 vppm

$$\frac{490\ mol\ S}{10^6\ mol\ LBG} x \frac{1\ mol\ SO_2}{1\ mol\ S} x \frac{64\ lb\ SO_2}{mol\ SO_2} x \frac{1\ mol}{379.7\ scf} x \frac{1\ scf}{133 x 10^{-6} MBtu}$$

= 0.621 lbSO_2/MBtu

Problem: Estimate thermal NOx emission factor for APS feed preheat furnace firing a mixture of 85% low Btu gas (LBG) (use the same composition as in Problem 2) and 15% natural gas. The furnace uses 350°F preheated combustion air.

Given:

Step 1 - Collect the fuel properties and operating conditions

Fuel H2 Content (%):	LBG: 15 Natural Gas: 0[a]
Combustion Air Preheat Temperature (°F):	350
Average Relative Humidity at Site (%):	30[a]
Unit Load Factor (%):	80[a]
Average Temperature at Site (°F):	60[a]
Burner Intensity Classification:	High _____ or Normal X[a]
Fuel Nitrogen Content (wt.%):	N/A
Fuel Firing Rate (MBtu/hr):	
Fuel HHV (appropriate units):	LBG: 133 Btu/scf Natural Gas: 1050 Btu/scf
NOx Reduction Technologies Used:	none

Note: (a) Assumed for lack of other data.

Step 2-9 Determine Thermal NOx Emission Factors

Base NOx emission factors (Table FHB.1) = LBG 0.07 lb/MBtu Natural Gas = 0.13 lb/MBtu

Type of Adjustment Factor	References	Adjustment Factor		Comment
		LBG	Nat. Gas	
H2 content adjustment	Table FHB.2	1.06	1.0	
At-the-source NOx reduction tech.	Table FHB.3	1.0	1.0	
Flue gas recirculation	Table FHB.4	1.0	1.0	
Air preheat	Table FHB.5	1.46	1.46	interpolate
Moisture content	Table FHB.6	1.0	1.0	
Load factor	Table FHB.7	1.0	1.0	
Burner intensity	Table FHB.8	1.0	1.0	

Thermal NOx Emission Factor for LBG = 0.07 lb/MBtu x 1.06 x 1.46 x 1.0

= **0.11 lb/MBtu**

Thermal NOx Emission Factor for Natural Gas = 0.13 lb/MBtu x 1.46 x 1.0

= **0.19 lb/MBtu**

Thermal NOx Emission Factor for

85/15% LBG/Natural Gas = 0.11 lb/MBtu x 0.85 + 0.19 lb/MBtu x 0.15

= **0.12 lb/MBtu**

Comparison to Actual Case

For a similar case in Rotterdam where the APS furnace fired 85/15% low Joule gas/high Joule gas (assume no fuel nitrogen), the measured NOx emission data was **27.6 g/GJ (0.064 lb/MBtu).**

References

Rotterdam Refinery NOx Emission Assessment Test Program, D.C. Rigano, 87.ECS1.88, April 9, 1987

Problem: Estimate NOx emission factors for a 3 cylinder Clark RA32 300 Hp engine fired by natural ga The natural gas contains 0.2 weight percent nitrogen as ammonia (NH_3).

a) Uncontrolled NOx
b) Reduction with 7° Timing Retard and Air/Fuel Ratio Timing

Step 1 - Collect the fuel properties and operating conditions

Fuel H2 Content (%):	0
Combustion Air Preheat Temperature (°F):	none
Average Relative Humidity at Site (%):	
Unit Load Factor (%):	
Average Temperature at Site (°F):	60
Burner Intensity Classification:	High ____ or Normal X
Fuel Nitrogen Content (wt.%):	0.2[a]
Fuel Firing Rate (MBtu/hr):	
Fuel HHV (appropriate units):	1050 Btu/scf
NOx Reduction Technologies Used:	none

Note: (a) Assumed for lack of other data.

Step 1 Spark ignited engines are usually fueled by natural gas. From Table ICE.1,
base IC engine NOx emission factor = 3.40 lb/MBtu

Step 2 No adjustment for humidity necessary

Step 3 No hydrogen adjustment

Step 4 Fuel NOx equivalency of N in the fuel

$$\frac{0.2\,lbN}{100\,lb\,nat.gas} x \frac{46\,lb\,NO_2}{14\,lbN} x \frac{16\,lb\,nat.gas}{1\,lb\,mol} x \frac{1\,lb\,mol}{379.7\,scf} x \frac{1\,scf}{1050 x 10^{-6}\,MBtu} = 0.26\ lb\ NO_2/MBtu$$

Step 5 Obtain the fuel nitrogen conversion to NOx factor from Table FHB.9. For a 0.2 wt. % fuel N, the conversion factor is 0.65.

Step 6 **Fuel NOx contribution** = 0.26 lb NO2/MBtu x 0.65 = **0.17 lb NO2/MBtu.**

Step 7 **NOx Emission Factor** = **Thermal NOx + Fuel NOx**
= **3.40 + 0.17**
= **3.6 lb NOx/MBtu**

Comparison with Actual Case
In a project where six similar engines were measured, the average NOx emission was 1610 ppmv. Assuming the measurements were made at 15% 0_2, this is equivalent to 5.6 lbs NOx/MBtu fired.

References
Alternative NOx Control Technology Documents - Engines P.D. Eichamer, 92.BCPRT.2217, June 24, 1992.

FUGITIVES

Fugitive emissions are leaks from valves, flanges, pump and compressor seals, sampling connections, open lines, and pressure relief valves. Generally, these emissions are not observed visually, but can be measured, in relatively low concentrations, at each component. The data needs for determining specific chemical fugitive air emissions are:

- the number of components (i.e., valves, flanges, pumps, compressors)
- the type of service the component is in (i.e. heavy liquid, light liquid, gas)
- the emission factor for each component, or the amount of specific chemical leaking per unit of time; and
- the chemical composition of the leaking vapors.

Table FUG.1 shows typical distributions of fugitive emissions among the various components covered in this section. Leaks from valves have been found to contribute about 50% of the total. However, as shown in the table, adopting a leak detection and repair program can significantly reduce the emissions.

Component counts and specific chemicals for individual operating units or designated areas (i.e., feed preparation, reactor, etc.) of a unit should be determined. Ideally, an operating unit is divided into separate emission areas whenever significant changes in chemical or physical composition occur and the fugitive emissions are estimated separately for each area.

In general, there are three fugitive emission estimating approaches.

- emission factors;
- established correlations that provide mass emission rate versus measured screening values
- direct measurement by bagging the source

Fugitive emissions regulations will become much more stringent in the next few years. New U.S. Federal regulations have decreased the leak definition from 10,000 ppm to 500 ppm for valves and 1,000 ppm for pumps. The San Francisco area is planning a 100 ppm leak definition for valves to become effective in 1997.

DRAFT

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DRAFT

Table FUG.1

Distribution of Fugitive Emission Sources

SOURCES	TYPICAL % OF FUGITIVE EMISSIONS	RESULTS OF RECENT U.S. SARA 313 STUDY*
VALVES	50	24
FLANGES	20	29
PRESSURE RELIEF VALVES	10	13
COMPRESSORS	10	22
PUMPS	5	4
DRAINS ETC.	5	8

Note: Significant variation from plant to plant and status of fugitives monitoring and maintenance (M&M program

* Refinery has quarterly valve monitoring and maintenance program

The methods used to estimate the fugitive emissions will usually depend on the information on component "counts" and if leak monitoring data are available. Figure FUG.1 is a decision tree that indicates the data requirements for each estimating approach. As shown in the figure, the accuracy of the estimate varies considerably among the approaches. The level of data requirements increases directly with the improvement in accuracy.

Table FUG.2 provides typical equipment counts for a 30,000 barrel/day refinery found by a 1980 EPA study. These data can be used as default values in the absence of a site or unit specific equipment component count.

Figure FUG.1

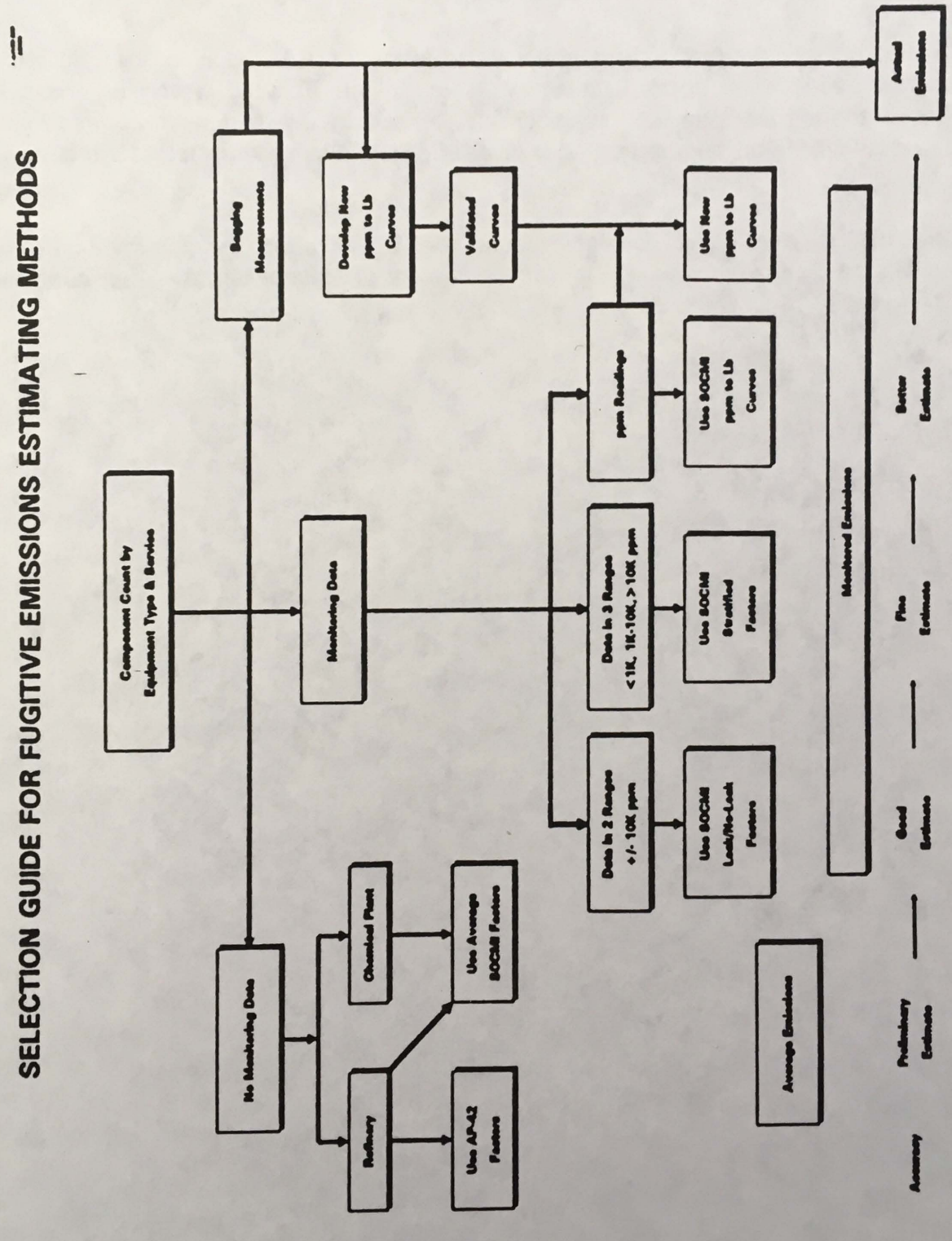

SELECTION GUIDE FOR FUGITIVE EMISSIONS ESTIMATING METHODS
Component Count by Equipment Type & Service
Monitoring Data
No Monitoring Data
Chemical Plant
Refinery
Use Average SOCMI Factors
Use AP-42 Factors
Bagging Measurements
Develop New ppm to Lb Curves
Validated Curves
Use New ppm to Lb Curves
Actual Emissions
ppm Readings
Use SOCMI ppm to Lb Curves
Data in 3 Ranges <1K, 1K-10K, >10K ppm
Use SOCMI Stratified Factors
Data in 2 Ranges +/- 10K ppm
Use SOCMI Leak/No-Leak Factors
Monitored Emissions
Average Emissions
Accuracy
Preliminary Estimate
Good Estimate
Fair Estimate
Better Estimate

Table FUG.2

ESTIMATED NUMBER OF INDIVIDUAL EMISSION SOURCES(2)
FOR SPECIFIC REFINERY PROCESS UNITS

Process Unit	Estimated Number of Sources Within Battery Limits of Process Units					
	Valves	Flanges	Pumps	Compressors	Drains	Relief Valves
Atmospheric Distillation	890	3540	31	1	69	6
Vacuum Distillation	500	2000	16	0(1)	35	6
Fuel Gas/Light Ends Procs.	180	760	3	2	11	6
Catalytic Hydroprocessing	650	2600	10	3	24	6
Catalytic Cracking	1310	5200	30	3	65	6
Hydrocracking	930	3760	22	3	58	6
Catalytic Reforming	690	2760	14	3	49	6
Aromatics Extraction	600	2400	18(1)	0(1)	41	6
Alkylation	680	2280	11	0	41	6
Delayed Coking	300	1240	9	0(1)	28	6
Fluid Coking	300	1240	9(1)	4	28	6
Hydroealkylation	690	3760	14(1)	3(1)	58	6
Treating/Dewaxing	600	2290	18	1[3]	44	6
Hydrogen Production	180	640	5	3	17	4
Sulfur Recovery	200	800	6(1)	0(1)	20	4

1 Sources were not counted in process units of this type. The number of sources was estimated.
2 Only those sources in hydrocarbon (or organic compound) service.
3 Number of compressor seals = 2.0 x Number of compressors.

REFERENCE: 1980 "RADIAN CORP" STUDY. EPA-600/2-80-075a, TABLE 5-16

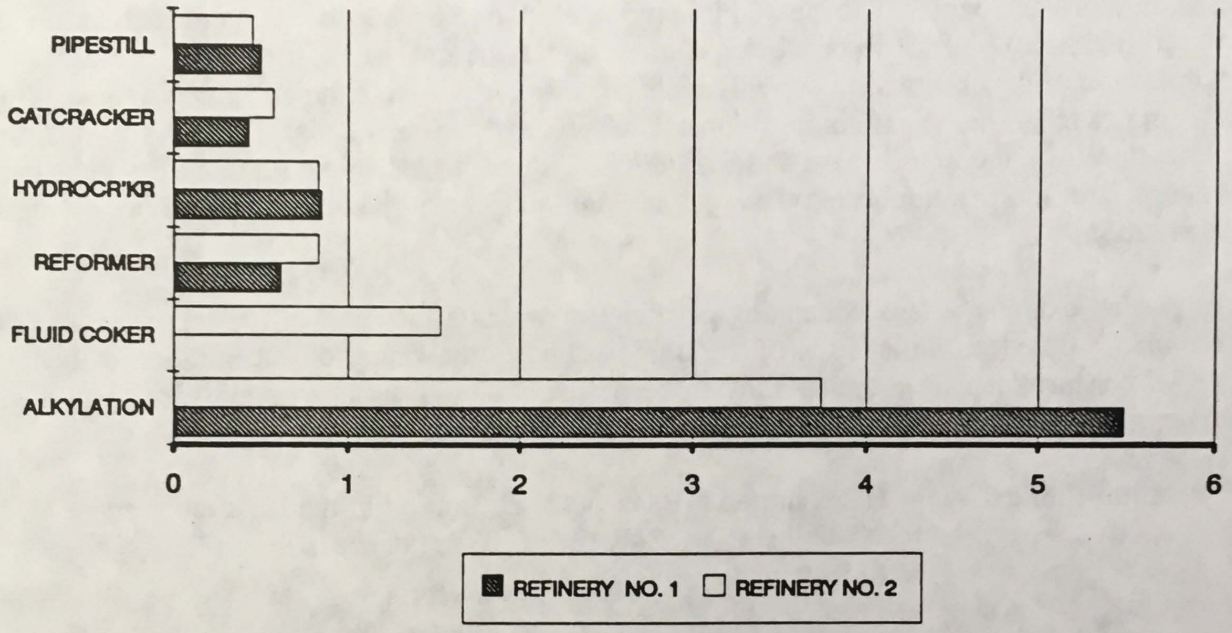
Table FUG.3

Average Number and Estimated Distribution of Valve and Pump Seals in Refinery Process Units

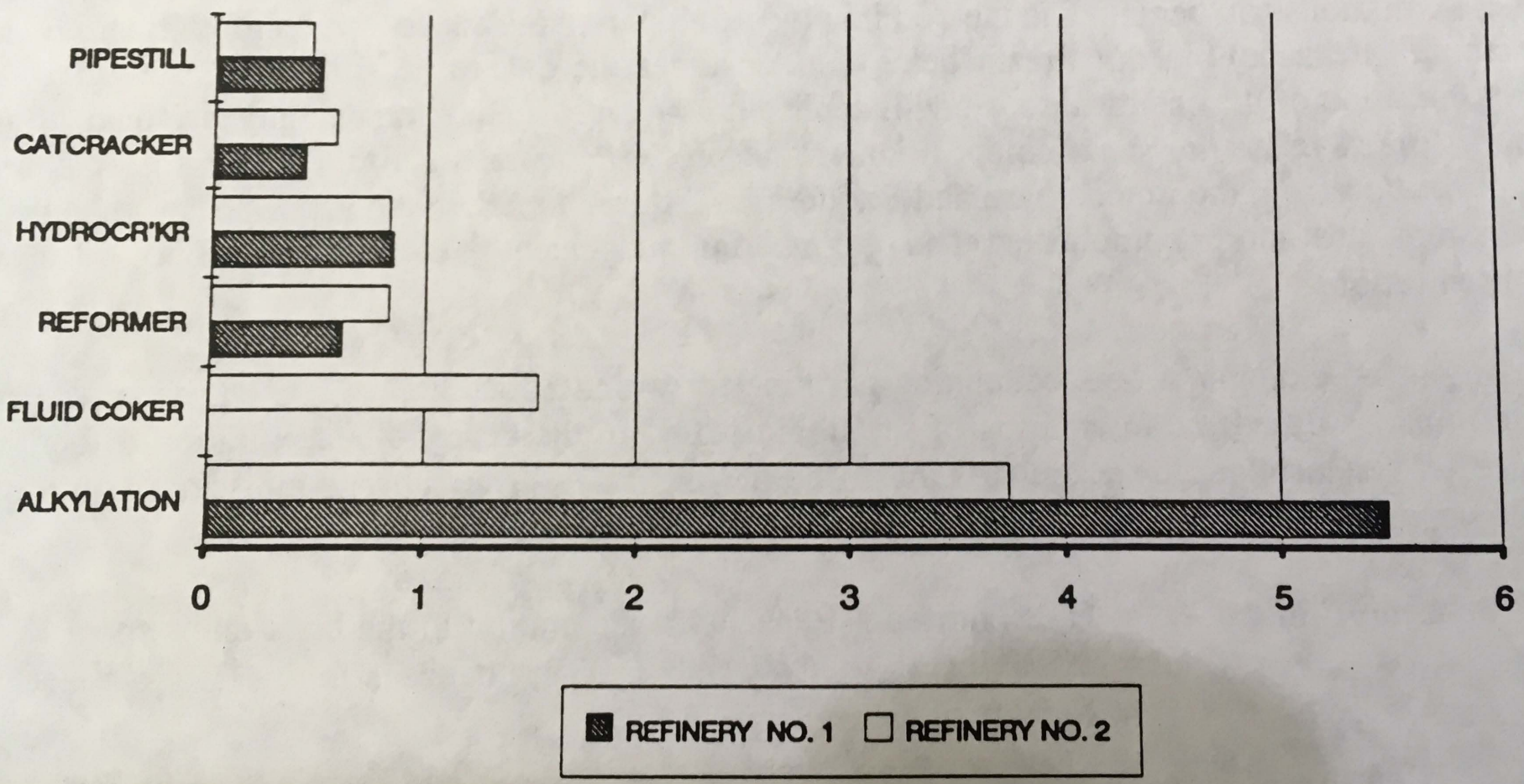
					Pump Service Distribution		Estimated Distribution of Valves, Number/Unit			Estimated Distribution of Pump Seals, Number/Unit		
	Avg. No. of Valves	Avg. No. of Pumps	Avg. No. of Compr.	Valve To Pump Ratio	Light Liquid Service %	Heavy Liquid Service %	Gas Service	Light Liquid Service	Heavy Liquid Service	Light Liquid Service	Heavy Liquid Service	Total Pump Seals
Atmospheric Distillation	893	31	1	29	35	65	90	281	522	15	28	43
Vacuum Distillation	500[1]	16[1]	0[1]	34	10	90	55[1]	50[1]	945[1]	2[1]	19[1]	21[1]
Fuel Gas/Light Ends Processing	181	3	2	60	83	17	88	77	16	4	0	4
Catalytic Hydroprocessing	645	10	3	65	67	33	335	208	102	9	5	14
Catalytic Cracking	1314	30	3	44	44	56	384	409	521	18	24	42
Hydrocracking	931	22	3	42	55	45	250	375	306	17	14	31
Catalytic Reforming	691	14	3	49	90	10	260	388	43	18	2	20
Aromatics Extraction	600[1]	18[1]	0[1]	33	90	10	60[1]	486[1]	54[1]	15[1]	2[1]	17[1]
Alkylation	571	11	0	52	100	0	230	341	0	15	0	15
Delayed Coking	300[1]	9[1]	0[1]	33	21[1]	79[1]	30[1]	57[1]	213[1]	3[1]	10[1]	13[1]
Fluid Coking	304	9	4	34	21	79	30	58	216	3	10	13
Hydrodealkylation	700[1]	14[1]	3[1]	50	90[1]	10[1]	266[1]	391[1]	43[1]	18[1]	2[1]	
Dewaxing/Treating	599	18	1	33	39	61	60	210	329	11	18	
Hydrogen Production	182	5	3	36	60	40	27	93	62	5	3	
Sulfur Recovery	200[1]	6[1]	0[1]	33	84[1]	16[1]	90[1]	90[1]	20[1]	8	2	10

[1]Source counts were not made in the field. These values are estimated.

Typical VOC Fugitive Emissions
Tons/Year Per 1000 Bbl/Day Feed To Process Unit



Typical VOC Fugitive Emissions
Tons/Year Per 1000 Bbl/Day Feed To Process Unit



In most cases, the hydrocarbon emission estimating methods discussed in this guidebook quantify the total hydrocarbon compounds (HC) released to the atmosphere. For many reporting requirements, determining the emissions of individual chemicals, a process called speciation, is also required. This section provides general information that is applicable to speciation of HC emissions.

Once the facility's fugitive, tankage, transfer, and secondary emissions are estimated the process of speciating these emissions can begin. The method involves multiplying the concentration of each individual chemical (for example, benzene) in the stream being emitted times the quantity of total HC's emitted. The appropriate concentration of the chemical to use will depend on the type of emission being determined. Fugitive emissions are assumed to be the same composition as the process stream. Tankage and transfer emissions involve a vaporization from the liquid phase and Raoult's law is used to obtain the vapor phase composition. Secondary emissions are more complicated and engineering judgement will be required to select the appropriate concentration.

Taking as an example a tank containing gasoline for which a total annual HC emission of 3,500 lbs has been determined. Based on an analysis of the liquid stored in the tank the concentration of benzene in the vapor space was determined by Raoult's Law to be 5 weight %. The benzene emission would be determined as follows:

Benzene Emitted = HCs emitted x Benzene concentration in the tank vapor space
= 3,500 lbs of VOCs/year x 0.05 lbs benzene/lb of HCs
= 175 lbs of Benzene per year

By repeating this procedure for all HC sources that contain benzene, the total amount of benzene emitted by the facility can be determined. Other chemical species that might be present in the gasoline, for example toluene, xylene and MBTE, would be determined in the same way.

In speciating HC emissions from fugitive emission sources (valves, pumps, flanges, relief valves, etc.) information on the type of service the source is in and on the composition of the process stream is required. The type of service falls into one of the four stream classifications used in the USEPA emission estimating methods from AP-42 which are described in Section 030: gas, hydrogen, light liquid, and heavy liquid. These have each been assigned different HC emission factors.

The first activity in developing speciated emissions is to separate the facility into process blocks or units. Refineries are usually separated by process units, such as the pipestill, alkylation unit, reformer, cat cracker, hydrotreater, etc. Larger refineries may have more than one of a particular unit. Chemical plants are usually segregated by process or product lines, for example the steam cracker or the MBTE unit. A simplified facility process flow diagram can usually provide the basis for segregating the facility into process blocks or units.

Once the facility has been segregated into process units, the next step is to determine the number of fugitive emission components that are in different types of service. This requires identifying the major streams entering and leaving the process unit. Typically, there will be one or two significant input streams and one to four output streams for a process unit and each of these streams is assigned to one of the types of service. An example showing the classification for several refinery streams will be found on page 3 of this section.

Determining the composition of the individual streams is needed if speciation is required. While a chemical analysis of the stream will provide the needed concentration for the chemical species present, such an analysis is often not available. Where analysis are not available, other sources of stream composition information that should be explored are operating personnel, crude or feedstock assays, and product specifications.

Average stream compositions may not be representative for a specific location since each is unique depending on the crude or feedstock used and the products desired. In comparing stream compositions determined for several of the SARA inventories in the USA, a wide range of compositions for similar streams was observed. However, in the absence of site specific information, some general guidance on the types and composition of chemical species in an individual process unit input or output stream can be made from a knowledge of the purpose of the unit and its operating conditions. The following tables provide such guidance for representative streams for five refinery process units. A discussion with each unit's operating personnel can usually identify the major chemicals present.

PROCESS UNIT STREAM COMPOSITION DATA

PROCESS UNIT/STREAM DESCRIPTION	AP-42 STREAM CLASSIFICATION	TYPICAL CHEMICALS IN THE STREAM
ATMOSPHERIC PIPESTILL		
Crude Feed	L.L.	Benzene, Toluene, Cyclohexane, etc.
Overhead Light Ends[1]	GAS	Ethylene, Propane, Butane
Naphtha	L.L.	Benzene, Toluene, Xylenes
Gasoline/Kerosine	H.L.	Benzene, Toluene, Xylenes
Gas Oil (AGO)[2]	H.L.	Naphthalene
Bottoms[3]	H.L.	Heavier Chemicals
FLUID CATALYTIC CRACKER		
AGO Feed[2]	H.L.	See Above
Cracked Light Ends[4]	GAS	Ethylene, Propylene
Cracked Naphtha[5]	L.L.	Benzene
Heavy Fuel Oil	H.L.	Naphthalene
POWERFORMER		
Naphtha Feed[5]	L.L.	Benzene, Toluene, Xylenes
Light Ends	GAS	Ethylene, Propylene
Reformate	L.L.	Benzene
ALKYLATION		
Butane Light Ends Feed[1]	GAS	Butanes
Olefin[4]	GAS	Ethylene, Propylene
Alkylate	L.L.	No SARA 313 Chemicals
COKER		
Bottoms Feed[3]	H.L.	See Above
Gasoline Overhead	L.L.	Benzene, Toluene, Xylenes
Gas Oil	H.L.	Heavier Chemicals
Coke	N.A.	

Superscripts indicate streams which may be the same or similar in composition.

TYPICAL PROCESS STREAM CONCENTRATIONS OF SPECIFIC HYDROCARBONS

Stream Concentration of Hydrocarbon weight %	Benzene	Biphenyl	Butadiene	Cumene	Cyclo-hexane	Ethyl-tene	Ethyl benzene	Naphtha-lene	Propyl-lene	Styrene	Toluene	TriMethyl-benzene	Xylenes	
Pipe Still														
Crude					1			1			1	1	1	Composition is Vari
Overhead Light Ends														
Naphtha	2				4		2				6	3	7	
Kerosine								4				2		
Gas Oil														
Bottoms														
FCCU														
Gas Oil Feed														AGO from PS
Cracked Light Ends						5			20					
Cracked Naphtha	1			1	2		2			2	7	2	9	
Heavy Fuel Oil								5						
Reformer														
Naphtha Feed														Naphtha from FCCU
Light Ends														
Reformate	6			2			5				15	3	23	
Alkylation														
Light Ends Feed														Light Ends from FC
Butane														Light Ends from PS
Alkylate														
Coker														
Bottoms Feed														Bottoms from PS
Coker Naphtha	1			1	1		1			1	3	1	7	
Coker Gas Oil		1						1						
Coke														

Note: Modified from a memo from P. J. Dennis to C. B. Barbre, "SARA Title 313 Chemicals Occurrence", 01136804.JPD, January 13, 1988

TYPICAL PROCESS STREAM CONCENTRATIONS OF SPECIFIC HYDROCARBONS

Stream Concentration of Hydrocarbon weight %	Benzene	Biphenyl	Butadiene	Cumene	Cyclo-hexane	Ethyl-lene	Ethyl benzene	Naphtha-lene	Propyl-lene	Styrene	Toluene	TriMethyl-benzene	Xylenes	
Pipe Still														
Crude					1			1			1	1	1	Composition is Vari
Overhead Light Ends														
Naphtha	2				4		2				6	3	7	
Kerosine								4				2		
Gas Oil														
Bottoms														
FCCU														
Gas Oil Feed														AGO from PS
Cracked Light Ends						5			20					
Cracked Naphtha	1			1	2		2			2	7	2	9	
Heavy Fuel Oil								5						
Reformer														
Naphtha Feed														Naphtha from FCCU
Light Ends														
Reformate	6			2			5				15	3	23	
Alkylation														
Light Ends Feed														Light Ends from FC
Butane														Light Ends from PS
Alkylate														
Coker														
Bottoms Feed														Bottoms from PS
Coker Naphtha	1			1	1		1			1	3	1	7	
Coker Gas Oil		1						1						
Coke														

Note: Modified from a memo from P. J. Dennis to C. B. Barbre, "SARA Title 313 Chemicals Occurrence", 01136804.JPD, January 13, 1988

SECTION	SUBJECT	DATE ISSUED
010-000	Introduction	March 93
-001	Speciation	March 93
020-000	Table of Contents	March 93
030-	AP-42 Emission Factors	March 93
-001	Background	March 93
-002	Table of AP-42 Factors	March 93
040-	SOCMI Emission Factors	March 93
-001	Background Information	March 93
-002	Average SOCMI Emission Factors	March 93
-003	SOCMI Leak/No Leak Emission Factors	March 93
-004	SOCMI Stratified Emission Factors	March 93
-005	Table of SOCMI Emission Factors	March 93
-006	Texas Air Control Board (TACB) Revision	March 93
-007	Table of TACB Emission Factors	March 93
050-	Unit Specific Method	March 93
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-002	Table of Unit Specific Method Equations	March 93
-003	Screening Default	March 93
060-	Mass Emission Rate vs. % Leaker Curves	March 93
-001	Background Information	March 93
-002	Table of EPA Regression Equations	March 93
080-	Fugitive Emissions Spreadsheet	March 93
-001	Background Information	March 93
-002	Table of Example Data	March 93
090	CMA POSSEE	March 93
-001	Background Information	March 93
200	Sample Problems	March 93
-001	SOCMI Emission Factors	March 93
-002	Mass Emission Rate vs. Screening Value	March 93

Emission Estimating Guide	Fugitive Emissions 030-001
Section: AP-42 Factors	**Subject:** Background Information

AP-42* includes specific fugitive emission factors developed for refinery process sources by Radian for EPA These factors are based on a large quantity of data and include average emissions by equipment type.

The AP-42 factors enable an emission to be determined with minimum information. Only a count of th component types and the service (e.g. gas, light liquids, etc.) are needed to estimate the emissions.

While providing a simple approach to emission estimates, field data indicate that the AP-42 factors provid estimates that are significantly in excess of actual emissions for sites which have a fugitive control progran in place.

* Compilation of air pollutant emission factors, AP-42, U.S. EPA, Sept. 1985 Including supplements A thru E.

To use the AP-42 factors a count of components for the unit or facility is required. This count should include pump seals, compressor seals, drains, and pressure relief valves in gas service. Additionally, a determination for the type of service, Hydrogen (H2), Gas, Light Liquid (LL), or Heavy Liquid (HL) is also required.

Hydrogen service is when the gas stream contains more than 50% hydrogen by volume. Gas service is when the material is a hydrocarbon gas/vapor at process conditions. Light liquid (LL) service is when the material is the liquid or gas/liquid stream has a vapor pressure greater than that of kerosine (>0.1 psia @ 100°F or 689 Pa @ 38°C) based on the most volatile component present at concentrations >20% by volume. Heavy Liquid service is when the material has a vapor pressure equal to or less than that kerosine as defined above.

Equipment Type	Count Needed	Type service needed (H2, Gas, LL, & HL)
Pump Seals	Yes	LL or HL
Compressors Seals	Yes	Gas or H2
Pressure Relief Valves (To Atm.)	Yes	Gas
Drains	Yes	All
Valves	No	All

Valves can either be counted directly (providing an improved estimate) or estimated based on the count of other components. To estimate the valves associated with each pump or compressor multiply the number of seals by 51 valves/seal. The total number of flanges can be estimated by multiplying total number of valves by 2.5 flanges/valve. The service of the valves and flanges is assumed to be the same as the pump or compressor's service, i.e. a LL pump has 51 valves in LL service. As with valves, an actual count of flanges will provide a better estimate.

The equipment count for pumps and compressors can be tabulated from several sources. The original design estimate or plans have a pump and compressor listing. The associated Piping & Instrumentation Diagrams will usually show pumps and compressors for the unit. The operating manual for the unit will list pumps and compressors and shall also indicate the service for each piece of equipment. The maintenance groups may have a record or listing of the pumps and compressors at each unit. One can obtain counts for pressure relief valves (PRVs) and drains from P&IDs and contact engineers. If none of these sources can provide the needed information, a brief unit walk through can be made to visually count the pumps and compressors.

The procedure to determine the release using AP-42 factors is:

Step 1 - Obtain a count for the number of components (valves, pumps, flanges, compressors, etc.)

Step 2 - Look up the appropriate average factors in Table FUG.4

Step 3 - Multiply the number of each type of component (Step 1) by the appropriate factor for that component in that service (Step 2) and sum overall to get the total fugitive emission.

Note: Many regulatory agencies allow a reduction of 75% from the AP-42 calculated emissions if a fugitives monitoring and maintenance program is used. Actual emissions have been found to be reduced by more than this allowance, however, so use of the average factors in this case would likely over predict fugitive emissions. Use of a more detailed method is recommended (See SOCMI Emission Factors 040-003).

Table FUG.4

AP-42 AVERAGE EMISSION FACTORS

SOURCE	SERVICE	EMISSION FACTOR (KG/DAY/SOURCE)
VALVES	GAS	0.64
	LL/GL	0.26
	HL	0.005
	H2	0.20
OPEN-ENDED VALVES	ALL	0.05
FLANGES	ALL	0.0061
PUMP SEALS	LL/GL	2.7
	HL	0.50
COMPRESSOR SEALS	GAS	15
	H2	1.2
DRAINS	ALL	0.76
RELIEF VALVES	GAS	3.9

LL = LIGHT LIQUID
GL = GAS/LIQUID MIXED PHASE
HL = HEAVY LIQUID

Emission factors have been determined for the Synthetic Organic Chemical Manufacturers Industry (SOCMI) by the USEPA. The use of USEPA's SOCMI fugitive emission factors is further explained in the Chemical Manufacturers Association (CMA) guidance document for estimating fugitive emissions.[3] These factors are used widely for refinery as well as chemical plant sources.

In summary, three sets of emission factors are available: average SOCMI, leak/no-leak, and stratified. Average SOCMI factors may be used when no monitoring and maintenance (M&M) program is conducted. The leak/no leak or stratified factors can be used when organic vapor analyzer (OVA) screening values are recorded from the leak detection program.

This method is similar to the AP-42 approach, and requires the least data. However, it will result in the highest fugitive emission rate estimate. In this method, the average factors from Table FUG.5 are used. The only information required is an equipment count for source/service type. If the process stream considered is a mixture of various chemicals and you only want the emissions of a particular compound, then multiply the factor by the appropriate weight percent of that chemical. It is assumed that the composition of the emissions is identical to the composition of the process stream.

Similar calculations would be done for gas valves, pump seals, etc. Emission rates for all source/service types would be summed to give the total plant fugitive emission rate.

Note: As with AP-42 average factors, many regulatory agencies allow a reduction of 75% from the SOCMI average calculated emissions if a fugitive monitoring and maintenance program is used. Actual emissions have been found to be reduced by more than this allowance, however, so use of the average factors in this case would likely over predict fugitive emissions. Use of a more detailed method is recommended (See SOCMI emission factors 040-003).

The procedure to determine the release using average SOCMI factors is:

Step 1 - Count the number of components (valves, pumps, etc.)

Step 2 - Look up the appropriate average factors in Table FUG.5.

Step 3 - Multiply the number of each type of component (Step 2) by the appropriate factor (Step 3) and sum over all item types to get the emission.

For using the leak/no leak emission factors, a leak is defined as a screening value of 10,000 ppm or greater as measured at the interface of the leak using EPA Method 21. The percentage of leaking components is then determined for each source type. Simple qualitative leak checks such as audible hissing, visible residue, discoloration, corrosion, or soap bubble tests do not determine the presence of a leaker. An overall emission factor can be obtained from the measured percentages of "leaking" and "nonleaking" sources using the factors for leaking and nonleaking sources listed in Table FUG.5. Each plant specific overall emission factor for each source type and service would be calculated as follows:

$$OEF = \frac{PCL \times LEF + (100 - PCL) \times NLEF}{100}$$

Where:

OEF	=	Overall Emission Factor
LEF	=	Leaker Emission Factor (> 10,000 ppmv)
NLEF	=	Nonleaker Emission Factor (< 10,000 ppmv)
PCL	=	Percent of Components Found Leaking
100-PCL	=	Percent of Components Found Not Leaking (Non-leaker)

If the stream is a mixture of various compounds and you only want the emissions of a particular compound, then multiply the factor by the appropriate percent composition. This assumes that the composition of emissions is the same as the stream composition.

For using the leak/no leak emission factors, a leak is defined as a screening value of 10,000 ppm or greater as measured at the interface of the leak using EPA Method 21. The percentage of leaking components is then determined for each source type. Simple qualitative leak checks such as audible hissing, visible residue, discoloration, corrosion, or soap bubble tests do not determine the presence of a leaker. An overall emission factor can be obtained from the measured percentages of "leaking" and "nonleaking" sources using the factors for leaking and nonleaking sources listed in Table FUG.5. Each plant specific overall emission factor for each source type and service would be calculated as follows:

$$OEF = \frac{PCL \times LEF + (100 - PCL) \times NLEF}{100}$$

Where:

OEF	=	Overall Emission Factor
LEF	=	Leaker Emission Factor ($>10{,}000$ ppmv)
NLEF	=	Nonleaker Emission Factor ($<10{,}000$ ppmv)
PCL	=	Percent of Components Found Leaking
100-PCL	=	Percent of Components Found Not Leaking (Non-leaker)

If the stream is a mixture of various compounds and you only want the emissions of a particular compound, then multiply the factor by the appropriate percent composition. This assumes that the composition of emissions is the same as the stream composition.

The procedure to use the SOCMI Leak/No Leak Factors is:

Step 1 - Screen all components with VOC Analyzer using EPA method 21.

Step 2 - Record each component as a leaker ($\geq$ 10,000 ppm) or non-leaker ($<$ 10,000 ppm)

Step 3 - Multiply the number of leakers or non-leakers in each component type by the appropriate emission factor

Step 4 - Add the contributions from each component type together.

Emission Rate = (number of leaking pumps) (leaking pump emission factor) + (number non-leaking pumps) (non-leaking pump emission factor) + (number of leaking valves) (leaking valve emission factor) + (number of non-leaking valves) (non-leaking valve emission factor) + ...

While the leak/no-leak approach assumes only two emission rates and two populations (i.e., leaking and non-leaking sources), the stratified method assumes three populations, breaking down the composite emission factor (average SOCMI factors) into 0-1,000 ppmv; 1,001-10,000 ppmv; and over 10,000 ppmv. Breaking the less than 10,000 range into two ranges is an improvement over the leak/no leak factors since experience shows a significant population below 1,000 ppmv.

This method requires that a complete component screening be conducted in accordance with EPA Method 21. All screening values must be recorded according to the range in which the value falls. Then, as with the leak/no-leak approach, the total emission estimate is generated by applying the number of components in each screening value range to the appropriate emission factor, and summing each subtotal.

The emission equation now becomes:

$$OEF = \frac{PCL1 \times LEF1 + PCL2 \times LEF2 + PCL3 \times LEF3}{100}$$

Where:

- OEF = Overall Emission Factor
- LEF(n) = Emission Factor For That Range
- PCL(n) = Percent of Components Found in That Range
- n = 1 Data Related to the 0-1,000 ppmv Screening Range
- n = 2 Data Related to the 1,001-10,000 ppmv Screening Range
- n = 3 Data Related to the greater than 10,000 ppmv Screening Range

The procedure to use the SOCMI Stratified Emission Factors is:

Step 1 - Screen all components using EPA method 21

Step 2 - Categorize each component as
- $\leq$ 10,000 ppm
- $>$ 1,000 ppm and $\leq$ 10,000 ppm
- $>$ 10,000

Step 3 - Multiply the number of components in each category by the appropriate emission factor to obtain range emission rate

Step 4 - Add range emission rates together to find total emission rate

Emission Rate = (number of pumps $\leq$ 1,000 ppm) ($\leq$ 1,000 ppm emission factor) + (number of pumps $>$ 1,000 need & $\leq$ 10,000) ($>$1,000 & $\leq$ 10,000 emission factor) + (number of pumps $>$ 10,000 ppm) ($>$10,000 emission factor) + ...

Table FUG.5
SOCMI EMISSION FACTORS

FUGITIVE EMISSION FACTORS AT A 10,000 PPMV LEAK DEFINITION
(This Leak Definition will be Lowered to 500 ppmv for US Chemical Plants Effective 1993.)
lb/hr/Source

			Leak/No-Leak		Stratified Emission Factors		
					Screening Value Range, ppmv		
Equipment	Service	Average SOCMI	Leaking Over 10,000	Non-Leaking 0-10,000	0-1000	1001-10,000	Over 10,000
Valves	Gas	0.01234	0.09940	0.00106	0.00031	0.00364	0.09940
	Light Liquid	0.01565	0.18778	0.00377	0.00062	0.02122	0.18778
	Heavy Liquid	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
Pump Seals	Light Liquid	0.10888	0.96315	0.02645	0.00436	0.07383	0.96315
	Heavy Liquid	0.04717	0.85625	0.02975	0.00838	0.20409	0.85625
Compressor Seals	Gas/vapor	0.50251	3.54403	0.19704	0.02495	0.58186	3.54403
Pressure Relief Seals	Gas/Vapor	0.22922	3.72696	0.09852	0.02513	0.61492	3.72696
Flanges	All	0.00183	0.08265	0.00013	0.00004	0.01929	0.08265
Open-Ended Lines	All	0.00375	0.02634	0.00331	0.00029	0.01931	0.02634
Sampling Connections	All	0.01500	--	--	--	--	--

Definition of Light Liquid: Per 40 CFR 60.485(e) (US EPA regulations)

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20C. Standard reference texts or ASTM D-2879 shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20C is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(1), (2), and (3) must all apply to be considered light liquid service.

SOCMI EMISSION FACTORS

FUGITIVE EMISSION FACTORS AT A 10,000 PPMV LEAK DEFINITION
(This Leak Definition will be Lowered to 500 ppmv for US Chemical Plants Effective 1993.)
lb/hr/Source

Equipment	Service	Average SOCMI	Leak/No-Leak		Stratified Emission Factors		
			Leaking Over 10,000	Non-Leaking 0-10,000	Screening Value Range, ppmv 0-1000	1001-10,000	Over 10,000
Valves	Gas	0.01234	0.09940	0.00106	0.00031	0.00364	0.09940
	Light Liquid	0.01565	0.18778	0.00377	0.00062	0.02122	0.18778
	Heavy Liquid	0.00051	0.00051	0.00051	0.00051	0.00051	0.00051
Pump Seals	Light Liquid	0.10888	0.96315	0.02645	0.00436	0.07383	0.96315
	Heavy Liquid	0.04717	0.85625	0.02975	0.00838	0.20409	0.85625
Compressor Seals	Gas/vapor	0.50251	3.54403	0.19704	0.02495	0.58186	3.54403
Pressure Relief Seals	Gas/Vapor	0.22922	3.72696	0.09852	0.02513	0.61492	3.72696
Flanges	All	0.00183	0.08265	0.00013	0.00004	0.01929	0.08265
Open-Ended Lines	All	0.00375	0.02634	0.00331	0.00029	0.01931	0.02634
Sampling Connections	All	0.01500	--	--	--	--	--

Definition of Light Liquid: Per 40 CFR 60.485(e) (US EPA regulations)

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20C. Standard reference texts or ASTM D-2879 shall be used to determine the vapor pressures.

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20C is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(1), (2), and (3) must all apply to be considered light liquid service.

In developing the SOCMI emission factor basis, data from an ethylene plant which had high emission factor compared with the other chemical unit factors were included. As a result, the combined emission factors fo all chemical plants in the study are considered excessive. The TACB considered this and issued revised factor that excluded the ethylene plant data for factors applicable to those installations that do not have ethylene units Table FUG.6 provides SOCMI emission factors with and without ethylene units, but factors for specific ethylene plants have not been calculated.

Table FUG.6
TACB EMISSION FACTORS

	SOCMI WITH ETHYLENE UNITS (LB/HR/SOURCE)	SOCMI WITHOUT ETHYLENE UNITS (LB/HR/SOURCE)
VALVES		
Gas	0.0123	0.0060
Light liquid	0.0157	0.0065
Heavy liquid	0.0005	0.0007
FLANGES		
All	0.0018	0.0005
Gas	-	0.0029
Light liquid	-	0.0005
Heavy liquid	-	0.0001
PUMPS		
Light liquid	0.1089	0.0873
Heavy liquid	0.0472	0.0496
COMPRESSORS		
All	0.5027	0.5027(1)
DRAINS		
All	0.0037	0.0037(1)
RELIEF VALVES		
All	0.2293	0.2293(1)
SAMPLE		
All	0.0331	0.0331(1)

(1) Factor has not been adjusted to omit ethylene plant data.

In addition to using emission factors, fugitive emissions can be estimated on a unit specific basis when exact screening values are recorded for each component. These values are then converted using an equation based on the same data as the SOCMI factors to obtain the leak rate. This method is more accurate since it does not lump measurements into just one, two, or three categories. It is recommended where numerical screening values are recorded. The equations are given in Table FUG.7. Compressors should use the "pumps - light liquid" equation. The equations are valid between 8-100,000 ppm. For values below 8 ppm default value (see pg. 050-003) and for screening values above 100,000 ppm use the "leak" factors from the leak/no-leak method.

The leak rate versus screening value equations are used to predict the mean emission rate of a population of fugitive emission sources (i.e., valves, flanges, etc.). The geometric average of the screening values of a group of sources is used in these equations to predict the mass emission rate for the group. This leak rate (lb/hr) is then multiplied by the equipment count to develop the total emission estimate for the source population.

Mathematical correlations offer an additional refinement to estimating emissions from equipment leaks by providing a continous function over the entire range of screening values instead of discrete intervals. The EPA has published correlations relating screening values to mass emissions rates. As shown in Table FUG.7, there are four equations which can be applied. The EPA's correlations are based upon OVA measurements taken using Method 21 calibrated to methane and corrected for the specific chemical response factor. Screening measurements used with these published correlations should be in the same format. For example, if a TLV instrument or an OVA calibrated to hexane were used to gather screening data, the data must be transformed to represent measurements gathered using an OVA, calibrated to methane, before using the published correlations. If a detector fails to meet Method 21 specifications or published transformations are not available, an instrument response curve must be developed to relate screening values to actual concentrations in the appropriate format (OVA/methane). Development of this screening value correction curve should be done in the laboratory before the detector is used in the field.

For many compounds, the instrument response factor is non-linear with screening value. In some cases, a single response factor adjustment at the leak definition of 10,000 ppm is adequate. If, however, the correlations are to be used, the best estimate of screening concentration over the entire range is needed. Therefore, a correction for non-linear response must be made. This can be accomplished in the laboratory by generating a response curve.

Table FUG.7
Table of Unit Specific Method Equations

PREDICTION EQUATIONS FOR NONMETHANE LEAK RATE FOR VALVES, FLANGES, AND PUMP SEALS IN SOCMI PROCESSES

VALID FOR MAXIMUM SCREENING VALUES < 100,000 PPM

SOURCE TYPE	INSTRUMENT	LEAST - SQUARES EQUATION[c]
Valves[a]		
Gas Service	OVA	$NMLK = 1.68 (10^{-5}) (MXOVA)^{0.693}$
Light Liquid Service	OVA	$NMLK = 3.74 (10^{-6}) (MXOVA)^{0.470}$
Flanges[b]	OVA	$NMLK = 3.74 (10^{-5}) (MXOVA)^{0.818}$
Pump Seals[a]	OVA	$NMLK = 1.34 (10^{-5}) (MXOVA)^{0.898}$

NMLK = Nonmethane leak rate (lb/hr)
MXOVA = Maximum screening value (ppmv) using an OVA instrument

[a]Source: Langley, G. J., and R. G. Wetherold (Radian Corporation) 1981. Evaluation of Maintenance for Fugitive VOC Emissions Control. EPA-600/52-81-080. pp. 54-56.

[b]Source: Wetherold, R. G., L. P. Provost, and C. D. Smith (Radian Corporation). Assessment of Atmospheric Emissions from Petroleum Refining: Volume 3. Appendix B. (Prepared for U.S. Environmental Protection Agency.) Research Triangle Park, North Carolina. Publication No. EPA-600/2-80-075c.

[c]NMLK is given in units of lb/hr. The units may have to be changed for reporting purposes.

Source: Improving Air Quality: Guidance for Estimating Fugitive Emissions from Equipment, Chemical Manufacturer's Association, Table G-5, p. 156.

The function describing the correlation of leak rate and screening value becomes discontinuous for zero and near zero values. Although the correlation function mathematically predicts zero emissions for zero readings on the portable instrument, mass emissions have been measured from equipment showing no screening concentration above zero. The reason for this involves the detector accuracy. To handle this discontinuity at the low end of the correlation, the EPA has derived a "default zero" screening value (8 ppm) and an associated mass emission rate for the screening values between zero and that default zero reading. These "default zero" values and emission rates shown below were derived from mass emissions data gathered in chemical plants.

Equipment Type/Service	"Default Zero" Screening Value, ppm	Zero Screening Value Emission Rate (lb/hr/source)
Valves, gas	8	0.000073
Valves, light liquid	8	0.000994
Flanges	8	0.000205
Pumps and all other components	8	0.000086

The regression equations in this section represent USEPA's latest thinking on how to estimate emissions fron facilities and is derived from the data analysis of the ethylene oxide/butadiene/phosgene producer studies in th US. This analysis was performed as part of the recently completed negotiated rulemaking for emissions fron leaking equipment (the new name for fugitive emissions). The USEPA analyzed the data from the produce group studies and produced emission factor curves which define the relationship between percent leakin sources at a given leak definition on the X-axis and the emission factor for the process unit on the Y-axis. The units of the relationships are percent expressed as 0-100% and emission factor expressed as lb/hr/individua source. The data was regressed using a standard regression package. Table FUG.8 gives the regressior equations for valves, flanges and pumps.

Using the attached information, at a 500 ppm leak definition for the valves, the equation is:

$$\text{Emission Factor (lb/hr/source)} = 3.33 \times 10^{-4}(\%\ \text{Leakers}) + 8.92 \times 10^{-4}$$

The results from this equation represent an emission factor for a process unit. The emission factor is multiplied by the equipment count to derive the unit emission estimate. For example, the emission factor for a plant with 2% leaking valves at a 500 ppm leak definition is 1.56×10^{-3} lb/hr/source. The analysis presented by USEPA in this attachment does not distinguish between valves in gas/vapor and light liquid service. All valves are treated the same using these correlations. The emission factor is multiplied times the equipment count to derive the emission estimate for the unit.

These equations should be used for plants conducting monitoring and maintenance programs with leak performance up to roughly 20% leaking sources at the given leak definition. For plants with higher percen leaking sources, the Unit Specific Method Equations in Table FUG.7 should be used.

For pumps, the double sealed pump equations apply to doubled sealed pumps with the seal pot reservoi connected to a control device. If the seal pot reservoir is vented, the single seal pump equations apply with the concentrations measured at the seal pot vent exit. The double seal pump equations apply to the outboard seal concentration measurements.

Table FUG.8
US EPA Regression Equations for Fugitive Emissions
As a Function of Leak Definition and Percent Leakers

Equipment Type	Leak Definition[1] (vppm)	Equation[2] (lb/hr/source)
Valves[3]	250	.000273(% leakers) + .000846
	500	.000333(% leakers) + .000892
	1000	.000403(% leakers) + .000948
Flanges[3]	250	.001260(% leakers) + .000328
	500	.001560(% leakers) + .000370
	1000	.001748(% leakers) + .000405
Single Seal Pumps	500	.000837(% leakers) + .000293
	1000	.001005(% leakers) + .000441
	2000	.001338(% leakers) + .000915
	5000	.001388(% leakers) + .001115
Dual Seal Pumps	100	.000469(% leakers) + .000134
	250	.000807(% leakers) + .000154
	500	.000928(% leakers) + .000187
	1000	.000983(% leakers) + .000289

1 Leak definition refers to the screening value above which corrective action is taken to lower emissions.

2 Applies to unit with monitoring and maintenance (M&M) programs per USEPA protocol.

3 All valves and flanges are light liquid or gas service.

A simple Lotus®123 spreadsheet, named FUGITIVE.WK2, has been developed to compile fugitive emission estimates. The "WK2" file extension is provided to avoid accidental erasure while saving emissions data. Th program inputs component counts, chemical composition, and emission factors, and calculates and tabulate emissions by chemical and plant area. As the file is retrieved, a menu allows the user the following choices

INPUT	to begin inputting fugitive emissions data
ADD	to add additional lines (with formulas) for data entry
CHANGE	to change emission factors
PRINT	to print a designated portion of the worksheet
SAVE	to save the worksheet
SORTCHEM	invoke Lotus®123 sort command to sort data by chemical/area
SORTAREA	sort data by area/component
REVISION	View/change notes on program revisions

This menu can be recalled at any time by typing "Alt M". To guard against inadvertent changes to th worksheet, the first five rows are titles and cells not requiring data entry and are copy protected. Row 5 i a blank row from which the formulas necessary to perform the calculations in the rest of the Spreadsheet ar copied. The period appearing in column "G" is a convenience provided to mark the rows that formulas hav been copied to.

An example printout of this worksheet is included as Section 080-002. The first three columns identify th plant, the area of the plant, and the chemical being considered. The chemical composition (weight percent for this area is input in the fourth column. The next three columns contain the type of component (i.e., valve flange), the number, and the service. From this information, the program will select the appropriate emissio factor from the table of emission factors input by the user. The component type and service must appea exactly as it does in the emission factor table or the correct emission factor will not be selected. Followin this information are columns for the "M&M factor" and hours on stream. The M&M factor is a percentag reduction in emission rate allowed by some states to account for a routine "monitoring and maintenance" program. If this factor is included, the calculated emissions will be reduced by the percentage input. Th actual M&M emission reduction value depends on leak detection monitoring frequency and the responsibl agency's directives.

The examples shown in Section 080-002 are for demonstration purposes only. The emissions are calculate in lb/yr when emission factors are given in kg/hr/source. This convention was adopted to facilitate SAR reporting which requires units of lb/yr. The last two columns summarize totals by chemical and area respectively. These columns contain formulas which check for changes in the "Chemical" or "Area" column to provide sub-totals.

Two versions of the FUGITIVE worksheet are shown in the computer output in Section 080-002; the f showing the data as input, the second showing the same data after using the SORTCHEM command rearrange it according to chemical name. In the original form, the "chemical totals" column is merely a rep of the "emission" column because the chemical name changes in every row. After sorting, the chemical to are produced, along with separate area totals for each chemical. A typical chemical plant will have orders- magnitude more data, making the totals columns much more meaningful. However, it is important remember the following cautionary remarks when using the SORTCHEM or SORTAREA commands:

- Each command prompts the user for a range to sort. Make sure that no columns containing formulas included in this range. Typically, a user will only need to increase the number of rows included in range by pressing the "down arrow" or "page down" keys.

- No blank rows should be included in the worksheet, nor should blank rows be inserted into the middle the worksheet. This does not cause a problem if no sorting is intended. However, if data containing blar is sorted, the blanks will all move to the top and the totals may be affected. Also, inserting rows chan the formulas in the totals columns, and this can affect the totals calculated.

- Each row should include an entry for "plant" and "area", so that this information will stay with t after sorting. Use the COPY command for repetitive entries of the same information.

It is suggested that two spreadsheets be maintained for each plant: one for the data as entered, one for sorted data. It will probably be easiest to enter data by plant area and component type (e.g., Area O Valves) and then by chemical composition. This information can be saved in the original form and then sor by chemical. After sorting, the data can be saved under a different name so the the original data is disturbed.

Although not incorporated in the spreadsheets, if a plant has a large percent of components in heavy liq service, a further refinement can be made to differentiate the emissions between condensables a noncondensables. Since heavy liquids are defined as streams with a boiling point greater than napthale (approx. 425°F); that is, vapor pressure less than 2.2 mm Hg at 68°F,[9] most of these emissions will conde as aerosols after exposure to atmospheric temperature and gravitate to the process sewer system. If light liqu (e.g., benzene) are present in the heavy liquid mixture, the chemical specific emissions can be approxima by multiplying the total emission estimate by the liquid composition (i.e., weight fraction of the compound interest).

EXAMPLE DATA

Data As Input

FUGITIVE EMISSIONS SUMMARY 12/09/90 TYPE "ALT H" FOR MENU
VERSION: 62989

PLANT	AREA	CHEMICAL	COMPOSITION wt %	COMPONENT TYPE	COUNT	SERVICE	NUM FACTOR	HOURS ON STREAM	EMISSION FACTOR	EMISSION kg/year	CHEMICAL TOTALS	AREA TOTALS
BAYPLACE	ONE	ALCOHOL	10	VALVE	100	GAS	75	8760	0.0056	122.64	122.64	
BAYPLACE	ONE	BENZENE	5	VALVE	100	GAS	75	8760	0.0056	61.32	61.32	
BAYPLACE	ONE	TOLUENE	10	VALVE	100	GAS	75	8760	0.0056	122.64	122.64	
BAYPLACE	ONE	XYLENE	15	VALVE	100	GAS	75	8760	0.0056	183.96	183.96	
BAYPLACE	ONE	ALCOHOL	10	PUMP SEAL	100	HL	75	8760	0.0214	468.66	468.66	
BAYPLACE	ONE	BENZENE	5	PUMP SEAL	100	HL	75	8760	0.0214	234.33	234.33	
BAYPLACE	ONE	TOLUENE	10	PUMP SEAL	100	HL	75	8760	0.0214	468.66	468.66	
BAYPLACE	ONE	XYLENE	15	PUMP SEAL	100	HL	75	8760	0.0214	702.99	702.99	2365.2
BAYPLACE	TWO	BENZENE	5	VALVE	20	HL		8760	0.00023	2.0148	2.0148	
BAYPLACE	TWO	TOLUENE	10	VALVE	20	HL		8760	0.00023	4.0296	4.0296	
BAYPLACE	TWO	XYLENE	15	VALVE	20	HL		8760	0.00023	6.0444	6.0444	
BAYPLACE	TWO	ALCOHOL	10	OPEN LINE	100	LL		8760	0.0017	148.92	148.92	
BAYPLACE	TWO	BENZENE	5	OPEN LINE	100	LL		8760	0.0017	74.46	74.46	
BAYPLACE	TWO	TOLUENE	10	OPEN LINE	100	LL		8760	0.0017	148.92	148.92	
BAYPLACE	TWO	XYLENE	15	OPEN LINE	100	LL		8760	0.0017	223.38	223.38	607.768

Data Sorted By Chemical

FUGITIVE EMISSIONS SUMMARY 12/09/90 TYPE "ALT H" FOR MENU
VERSION: 62989

PLANT	AREA	CHEMICAL	COMPOSITION wt %	COMPONENT TYPE	COUNT	SERVICE	NUM FACTOR	HOURS ON STREAM	EMISSION FACTOR	EMISSION kg/year	CHEMICAL TOTALS	AREA TOTALS
BAYPLACE	ONE	ALCOHOL	10	VALVE	100	GAS	75	8760	0.0056	122.64		
BAYPLACE	ONE	ALCOHOL	10	PUMP SEAL	100	HL	75	8760	0.0214	468.66		591.3
BAYPLACE	TWO	ALCOHOL	10	OPEN LINE	100	LL		8760	0.0017	148.92	740.22	148.92
BAYPLACE	ONE	BENZENE	5	VALVE	100	GAS	75	8760	0.0056	61.32		
BAYPLACE	ONE	BENZENE	5	PUMP SEAL	100	HL	75	8760	0.0214	234.33		295.65
BAYPLACE	TWO	BENZENE	5	VALVE	20	HL		8760	0.00023	2.0148		
BAYPLACE	TWO	BENZENE	5	OPEN LINE	100	LL		8760	0.0017	74.46	372.1248	76.4748
BAYPLACE	ONE	TOLUENE	10	VALVE	100	GAS	75	8760	0.0056	122.64		
BAYPLACE	ONE	TOLUENE	10	PUMP SEAL	100	HL	75	8760	0.0214	468.66		591.3
BAYPLACE	TWO	TOLUENE	10	OPEN LINE	100	LL		8760	0.0017	148.92		
BAYPLACE	TWO	TOLUENE	10	VALVE	20	HL		8760	0.00023	4.0296	744.2496	152.9496
BAYPLACE	ONE	XYLENE	15	PUMP SEAL	100	HL	75	8760	0.0214	702.99		
BAYPLACE	ONE	XYLENE	15	VALVE	100	GAS	75	8760	0.0056	183.96		886.95
BAYPLACE	TWO	XYLENE	15	OPEN LINE	100	LL		8760	0.0017	223.38		
BAYPLACE	TWO	XYLENE	15	VALVE	20	HL		8760	0.00023	6.0444	1116.374	229.4244

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To continue the example, suppose that 95% of the screening values below 1,000 ppm are in the non-detectat (zero) range. The default zero value is applied to all readings below 8 ppm. The correlation equation f valves in light liquid service found in Section 070-002 is applied to each individual screening value above ppm (no averaging of screening values before calculating the emissions rate with the equation). For examp if a valve screens at 6,800 ppm, the equation is:

Nonmethane leak rate (lb/hr) $= 8.218(10^{-4.342})(6{,}800 \text{ ppm})^{0.470}$

$= 0.024$ lb/hr

Summing all these individual leak rates gave the following results:

Zeros: 570 valves x 0.000994 lb/hr/valve x 8760 hr/yr = 5,000 lb/yr
Other: 61 valves x various emission rates x 8760 hr/yr = 9,600 lb/yr

Total: 631 valves 14,600 lb/yr

In this example, the four SOCMI emission factor approaches gave the following estimates:

Average SOCMI Factors	Leak/No Leak Factor
86,000 lb/yr	30,900 lb/yr
Stratified Factors	Leak Rate/Screening Value
18,300 lb/yr	14,600 lb/yr

Note that in this example a high percent of the valves were screened at zero. For comparison, the avera refinery had only 42% screen at zero. Since the petroleum refinery screening value distributions are embodi in the emission factors, these factors will all overestimate chemical plant emissions.

The CMA POSSEE System is a PC-based computer software package designed with the following objective

- Develop a speciated emission estimate for fugitive emissions using all available calculation techniqu including emission factors as well as EPA and bagging data correlation curves.

- Provide the means to build an industry-wide data base for the purpose of better understanding of t underlying causes of fugitive emissions. This should lead to better estimates of these emissions as we as increased knowledge about how to reduce these emissions.

The CMA POSSEE System is divided into three phases:

Phase I - Data Entry for Individual Plants;

Phase II - Plant Emission Report Generation and Data Analysis;

Phase III - Data Base Construction and Data Analysis.

The Phase I data entry system is available now as POSSEE version 1.1 and can be purchased from CMA. T system is menu-driven and accepts screening data and bagging data. The purchased version of POSSEE w produce several reports. In Phase II, the plant submits the accumulated plant data to CMA. CMA adds th data to their data base and produces, for a nominal fee, an additional set of reports from plant data which sent back to the plant. Steps are taken to assure the confidentiality of data. Phase III will use the accumulat data to 1) validate leak models and 2) conduct statistical analyses of the data.

The system has the capability to export data to ASCII files for external analysis. The system will also ha the capability of importing data for analysis from ASCII files.

Average SOCMI Emission Factors

Data taken from a 100% valve survey of solvent equipment in a plant without a fugitive emission monitorin program produced the following fugitive emission estimate:

Required Data:	631 valves in light liquid service
Emission Factors:	0.0156 lb/hr/valve (Table III-2)
Calculation:	631 valves x 0.0156 lb/hr/valve = 9.8 lb/hr
Emission Rate:	86,000 lb/yr

SOCMI Leak/No Leak Emission Factors

Now consider the overall emission rate in the previous example where only 1.0% leakers were found in th screening of all the light liquid valves.

Now consider the overall emission rate in the previous example where only 1.0% leakers were found in the screening of all the light liquid valves.

Required Data:	631 valves 1% leakers at > 10,000 ppmv (PCL = 1)
Emission Factors: (Table FUG.4)	Leaker = 0.1878 lb/hr Non-Leaker = 0.0038 lb/hr
Calculations:	$OEF = \frac{1 \times 0.1878 \text{ lb/hr} + (100 - 1) \times 0.0038 \text{ lb/hr}}{100}$
	OEF = 0.0056 lb/hr/valve
	Rate = 631 valves x 0.0056 lb/hr/valve = 3.53 lb/hr
Emission Rate:	30,900 lb/yr

This highlights a significant disadvantage of this method. Because the NLEF applies even to "non-leakers registering no detectable leak concentrations, a high minimum overall plant fugitive emission rate result. Using this method, a minimum of 20,800 lb/yr would be established. (For NLEF = 100; overall emission rate = 0.0038 lb/hr x 631 x 8760 = 20,800 lb/yr.)

SOCMI Stratified Emission Factors

Lets look at the previous example, but now considering a further breakdown of the screening data. We still have 1% of the components screening above 10,000 ppmv. However, when we screened, we found that 95% of the components had screening values less than 1,000 ppmv.

Required Data:

631	valves
95%	screened below 1,000 ppmv (PCL1=95)
4 %	screened between 1,001 and 10,000 ppmv (PCL2=4)
1 %	screened above 10,000 ppmv (PCL3=1)

Emission Factors: (Table FUG.4)

PCL1 = 0.00062 lb/hr
PCL2 = 0.02122 lb/hr
PCL3 = 0.1878 lb/hr

Calculations:

$$\frac{95 \times 0.00062 \text{ lb/hr} + 4 \times 0.02122 \text{ lb/hr} + 1 \times 0.1878 \text{ lb/hr}}{100}$$

OEF = 0.00332 lb/hr/valve
Rate = 631 valves x 0.00332 lb/hr/valve = 2.092 lb/hr

Emission Rate: 18,300 lb/yr

Since those components that screened below the non-detectable limits of the instrument are assigned an emissio factor, you still are faced with a minimum overall plant fugitive emission rate. In our example, that rate woul be 3,400 lb/yr (for PCL1=100; overall emission rate = 0.00062 x 631 x 8760 = 3,400 lb/yr).

TANKS

Emissions from three types of tanks are considered in this section: fixed roof, internal floating roof, and external floating roof. The source document for the formulas used to model internal floating roof tanks is EPA's Compilation of Air Pollutant Emission Factors, AP-42, Fourth Edition, Volume I, which was issued in September of 1985. Emissions from external floating roof tanks are estimated using American Petroleum Institute (API) Publication 2517, Third Edition, February 1989. Emissions from fixed roof tanks are estimated using API Publication 2518, 2nd Edition, October 1991.

The correlations presented in AP-42 and API 2517 were developed to predict emissions of Volatile Organic Compounds (VOC) from tanks containing organic liquids of known vapor pressure. The estimated total emissions from a tank have to be multiplied by a weight fraction vapor composition to obtain the emission quantity of a specific chemical. Because the vapor composition in a tank is rarely known, Raoult's Law is used to relate the vapor composition to the liquid composition.

Summaries of the factors and equations used in estimating tank emissions are presented in Sections 040 to 060. Section 040 covers the fixed roof tanks. The two types of losses from fixed roof tanks are breathing losses, which result from expansion of the vapor with temperature change, and working losses, which result from the expulsion of vapor during filling operations. While not explicitly stated in AP-42, it is strongly implied that the equations presented in Section 040-001 apply to tanks equipped with a pressure-vacuum (PV) vent. Specifically, the fixed roof tanks "...must be substantially liquid and vapor tight and must operate approximately at atmospheric pressure."

Sections 050 and 060 cover floating roof tanks and the types of emissions or losses from these types of tanks. The equations presented in Sections 050 and 060 apply to "freely vented" internal floating roof and external floating roof tanks. Internal floating roof tanks are subject to four types of loss: rim seal, deck fitting, deck seam, and withdrawal loss. External floating roof tanks are not subject to deck seam losses because their decks are welded.

The current (fourth) edition of AP-42 was issued in September, 1985. Since then, the current (third) edition of API 2517 was issued in February, 1989. The primary modification to API 2517 was the inclusion of deck fitting loss equations which was not available in the earlier edition. A new edition of API 2518 concerning fixed roof tanks was released in October 1991. This document corrects the breathing losses by adding a "vented vapor saturation" factor.

DRAFT

The hydrocarbon emissions covered in this guidebook in many cases the result of vaporization of a pure component or a liquid mixture. Therefore, the determination of the vapor pressure is a key input for most of the emission estimating procedures discussed and this section describes alternate sources for this information.

True vapor pressure (TVP) is the vapor pressure of a material (either a mixture or a pure component) at the storage temperature of the material. For a pure component, the vapor pressure can be obtained from one of many publications on physical properties of materials. The vapor pressure is usually provided at a specific temperature, for example:

760 mm Hg @ 0°C for Water

or

1.2 psia @ 60°F for Benzene

Form liquid mixture, determining the vapor pressure requires information on the chemical and physical properties. In the case of petroleum liquids, this data is often the Reid Vapor Pressure (RVP). Relationships between the RVP and TVP at different temperatures are available. For example a gasoline with an RVP of 13 psia (winter gasoline) stored at a temperature of 60°F has a TVP of 6.9 psia. Nomographs relating RVP and TVP for crude oil, motor gasoline, and naphthas can be found in Section 040-004 of the Tank Section and relationships for heavier materi are listed in Table 7 of Section 040-004 of the Tank Section.

If a chemical analysis of the liquid mixture is available, Raoult's Law can be used to calculate the vapor pressure of the mixture from the vapor pressure of the pure components. Further discussion on the use of Raoult's Law for this purpose can be found in Section 070-001 of the Tanks Section.

SECTION	SUBJECT	DATE ISSUED
010-000	Introduction	March 93
-001	Vapor Pressure Determination	March 93
020-000	Table of Contents	March 93
040-	Fixed Roof Tanks	March 93
-000	Background Information	March 93
-001	Determining the Emission	March 93
-002	Factors/Equations	March 93
-003	Example Calculation	March 93
-004	Tables and Figures	March 93
050-	External Floating Roof Tanks	March 93
-000	Background Information	March 93
-001	Determining the Emission	March 93
-002	Factors/Equations	March 93
-003	Example Calculation	March 93
-004	Tables and Figures	March 93
-005	Roof Landings/Change of Service	March 93
060-	Internal Floating Roof Tanks	March 93
-001	Factors/Equations	March 93
-002	Example Calculations	March 93
070-	Speciation	March 93
-001	Background/Information	March 93
-002	Example Calculation	March 93
080-	Lotus Tanks Spreadsheets	March 93
-001	Detailed Instructions	March 93
-002	Example Outputs (FR, EFR,IFR)	March 93

The emissions from fixed roof tanks is due to evaporation of the contained liquid. There are two mechanisms for emissions:

- Standing storage loss
- Working loss

Standing storage loss is associated with the thermal expansion and contraction of the vapor space that results from the daily temperature cycle. It is sometimes referred to as breathing loss. Working loss is associated with the displacement of vapor resulting from a change in liquid level.

The calculation procedures in this section determine the total emission based on the average molecular weight and vapor pressure of the contained liquid. To determine the emission of individual components of a mixture refer to the speciation procedures in sub-section 070 of this section.

The following is a list of data one needs and possible sources of information.

Data	Unit	Where
Liquid Type and Composition	mol fraction	8
Bulk liquid temperature	°F	see Section 040-001
Atmospheric Pressure	psia	3,4
Tank Diameter	ft.	2
Vapor Space Height	ft.	2
Temperature Swing	°F	3,4
Paint	color type	1
Tank Capacity	gal	2
Throughput	gal/yr	5
Tank Roof Type	cone or dome	2
Solar Insulation	-	3,4

1) Maintenance Records
2) Facility construction drawings
3) Local meteorological station
4) Almanac
5) Facility Production Reports
6) Inspection Reports
7) Published Data
8) Laboratory Analysis
9) Process Design Data
10) Measurement of the stock liquid level

The procedure to calculate the release is:

Step 1 - Gather the data identified in 040-000, page 2.

Step 2 - Determine the true vapor pressure (TVP) for the liquid composition. The method used for this determination will depend on whether the liquid is a pure component or a mixture and on the properties that may be known about the liquid (e.g. the Reid Vapor Pressure (RVP) may be known, thereby enabling the use of nomograms in Section 040-001 relating RVP and liquid temperature).

Step 3 - Calculate the annual turnover from the formula on page 040-001.

Step 4 - Determine the solar absorptance, product factor, vapor saturation factor and turn over factor from the figures and tables in Section 040-001.

Step 5 - Calculate breathing loss and working loss from equations on page 040-001.

Step 6 - Add breathing loss and working loss to determine annual emission.

Table II-1 - FIXED ROOF TANK LOSSES
Summary of Factors/Equations Used in API 2518, 2nd Edition

Type of Loss	Standing Loss(L_s)	Working Loss(L_w)
Equation	$L_S = 365\ V_V\ W_V\ K_E\ K_S$	$L_W = 0.0010\ M_V\ P_{VA}\ Q\ K_N\ K_P$
Factor Description		
M_V Vapor Molecular Weight, lb/lb-mole	X	X
P_{VA} True Vapor Pressure, psia	[=exp(A-(B/T_{LA}))] or figure 5 and 8.	X
A Vapor Pressure Equation Constant	X	-
B Vapor Pressure Equation Constant, °R	X	-
T_{LA} Daily Average Liq Surface Temp, °R	[=0.44T_{AA}+0.56T_B+0.0079aI]	-
T_{AA} Daily Average Ambient Temp, °R	X	-
T_B Liquid Bulk Temperature, °R	[=T_{AA}+6a-1]	-
a Tank Paint Solar Absorptance	See Table 5.	-
I Solar Insolation, Btu/ft^2 day	See Table 4.	-
Q Throughput, Bbl/yr	-	X
N Stock Turnover rate	-	[=5.614*Q/V_{LX}]
V_{LX} Tank Maximum Liquid Volume, ft^3	-	[=(1/4)PI*D^2*H_{LX}]
H_{LX} Stock Maximum Liquid Height,ft	-	X
K_N Turnover Factor	-	For N>36 = (180+N)/6N, other=
1.0		
K_P Product Factor	-	= 0.75 for crude, other= 1.0
V_V Tank Vapor Space Volume ft^3	[=(1/4)PI*D^2*H_{VO}]	-
H_{VO} Vapor Space Outage, ft	[=H_S-H_L+H_{RO}]	-
H_S Tank Shell Height, ft	X	-
H_L Tank Liquid Height, ft	X	-
H_{RO} Roof Outage, ft	[=(1/3)*H_R] CONE ROOF	-
	[=H_R((1/2)+(1/6)*(H_R/R_S)^2)] DOME ROOF	-
H_R Tank Roof Height, ft	[=S_R*R_S] CONE ROOF	-
	[=R_R-((R_R)^2-(R_S)^2)$^{0.5}$] DOME ROOF	-
S_R Tank Cone Roof Slope, ft/ft	Default = 0.0625	-
R_S Tank Shell Radius, ft	X	-
R_R Tank Dome Roof Radius, ft	Default = D	-
W_V Stock Vapor Density, lb/ft^3	[=(M_V*P_{VA})/(R*T_{LA})]	-
R Ideal Gas Constant, psi ft^3/mol °R	10.731	-
K_E Vapor Space Expansion Factor	[=(ΔT_V/T_{LA})+((ΔP_V-ΔP_B)/(P_A-P_{VA}))]	-
ΔT_V Daily Vapor Temp Range, °R	[=0.72ΔT_A+0.028aI]	-
ΔT_A Daily Ambient Temp Range, °R	X	-
ΔP_V Stock Daily Vapor Pressure Range, psi	[=P_{VX}-P_{VN}]	-
P_{VX} Stock VP @ Max Liq Surface Temp, psi	[=exp(A-(B/T_{LX}))]	-
P_{VN} Stock VP @ Min Liq Surface Temp, psi	[=exp(A-(B/T_{LN}))]	-
T_{LX} Daily Max Liquid Surface Temp, °R	[=T_{LA}+0.25ΔT_V] or Figures 5 and 8.	-
T_{LN} Daily Min Liquid Surface Temp, °R	[=T_{LA}-0.25ΔT_V] or Figures 5 and 8.	-
ΔP_B Breather Vent Pressure Range, psi	Default = 0.06	-
P_A Atmospheric Pressure. psi	X	-
K_S Vented Vapor Saturation Factor	[=1/(1+0.053*P_{VA}*H_{VO})]	-

X means parameter is included in above correlation.
- means parameter is not included in above correlation.

Sample Problem (from API Publication 2518, Second Ed., Oct., 1991.)

Problem

Estimate the total evaporative loss, in pounds per year, given the following information:

A fixed-roof tank has the following characteristics:

a. A diameter of 100 feet.
b. A shell height of 40 feet.
c. A cone roof with roof slope of 0.0625 feet per foot.
d. A liquid level of 20 feet.
e. A maximum liquid level of 38 feet.
f. The tank is painted white, and the paint is in good condition.
g. The breather vent pressure setting is 0.03 pounds per square inch gauge and the breather vent vacuum setting is -0.03 pounds per square inch gauge.

The product stored in the tank has the following characteristics:

a. A stock of US midcontinent crude oil.
b. Reid vapor pressure of 2.0 pounds per square inch.
c. The stock vapor and liquid composition are not given.
d. An annual net throughput of 1.5 million barrels per year.

The ambient conditions are as follows:

a. A daily maximum ambient temperature of 50°F.
b. A daily minimum ambient temperature of 70°F.
c. A daily total solar insolation on a horizontal surface of 1,200 British thermal units per square foot day.
d. An atmospheric pressure of 14.7 pounds per square inch absolute.

Calculation: Total Loss = Standing (breathing) Loss + Working Loss.

(a) Standing Loss - Calculate using Equation 1.

$$L_s = 365\ V_v\ W_v\ K_E\ K_s \quad (1)$$

where:

L_S = Standing Loss (lb/yr)

V_V = 165,300 ft^3.

where:

R_S = 50 ft. (assumed R_S = D/2)
S_R = 0.0625 (default)
H_R = R_S*S_R =3.125 ft.

H_{RO} = (1/3)*H_R = 1.042 ft.

H_L = 20 ft. (assumed H_L = H_S/2)
H_S = 40 ft. (given)
H_{VO} = H_S-H_L+H_{RO} = 21.04 ft.

V_V = (1/4)*PI*D^2*H_{VO} = 165,300 ft^3.

W_V = 0.007599 lb/ft^3.

where:

M_V = 50.00 lb/lb-mole (taken from 19.1.2.2.2.8.1.2 API 2518)
R = 10.731 psia ft^3/lb-mole °R.
a = 0.17 (from Table 5 for white shell and roof)
I = 1,200 Btu/ft^2 day. (given)
T_{AA} = 519.67 °R (given; °F + 459.58)

T_B = T_{AA}+6a-1 = 519.69°R

T_{LA} = 0.44T_{AA}*0.56T_B*0.0079aI = 521.29°R (61.62°F)

A = 12.82-0.9672 ln(RVP) = 12.15
B = 7261-1216 ln(RVP) = 6418°R
P_{VA} = exp[A-(B/T_{LA})] = 0.8501 psi.

W_V = M_V*P_{VA}/R/T_{LA} = 0.007599 lb/ft^3.

$KE = 0.0489$

where:

$\Delta T_A = 20°R$ (given)

$\Delta T_V = 0.72\Delta T_A + 0.028aI = 20.11\ °R$

$T_{LX} = T_{LA} + 0.25\Delta T_V = 526.32°R\ (66.65°F)$
$T_{LN} = T_{LA} + 0.25\Delta T_V = 516.27°R\ (56.60°F)$

$P_{VX} = \exp[A-(B/T_{LX})] = 0.9563$ psi.
$P_{VN} = \exp[A-(B/T_{LX})] = 0.7541$ psi.
$\Delta P_V = P_{VX} - P_{VN} = 0.2022$ psi.

$P_{BP} = 0.03$ psi. (given)
$P_{BV} = -0.03$ psi. (given)
$\Delta P_B = P_{BP} - P_{BV} = 0.06$ psi.
$K_E = (\Delta T_V/T_{LA}) + [(\Delta P_V - \Delta P_B)/(P_A - P_{VA})] = 0.04885$

$K_S = 1 / [1 + (0.053 * P_{VA} * H_{VO})] = 0.5133$

$$L_S = 365\ (165{,}300)\ (0.007599)\ (0.04885)\ (0.5133) = 11{,}490\ \text{lb/yr.}$$

(b) Working Loss - Calculate using Equation 2.

$$L_W = 0.0010\ M_V\ P_{VA}\ Q\ K_N\ K_P \quad (2)$$

where:

$M_V = 50.00$ lb/lb-mole.
$P_{VA} = 0.8501$ psi.
$Q = 1{,}500{,}000$ bbl/yr.
$K_P = 0.75$ (appropriate for crude oil stocks)
$K_N = 1.00$

where:

H_{LX} = 38 ft. (given)

$V_{LX} = (PI/4)*D^2*H_{LX}$ = 298,500 ft^3.
$N = 5.614*Q/V_{LX}$ = 28.22
K_N = 1.00 (when $N \leq 36$)

$$L_W = 0.0010\ (50.00)\ (0.8501)\ (1,500,000)\ (0.75)\ (1.00) = 47,820 \text{ lb/yr.}$$

(c) Total Loss - Calculate using Equation 3.

$$L_T = L_S + L_W \quad (3)$$

L_T = 11,490 + 47,820 = 59,310 lb/yr.

The following tables and figures are required to estimate the emissions from fixed roof tanks. They are taken from API Publication 2518, 2nd Edition, October 1991.

Table 1 - Nomenclature

Symbol	Description	Units	Reference Information		
			Equations	Tables	Figures
A	constant in the vapor pressure equation	dimensionless	29, 32	6, 7	3, 6
B	constant in the vapor pressure equation	$^{\circ}R$	30, 33	6, 7	4, 7
D	tank diameter	ft	---	---	1
H_L	stock liquid height (or inage)	ft	---	---	1
H_{LX}	stock maximum liquid height	ft	---	---	---
H_R	tank roof height	ft	13, 15	---	1
H_{RO}	roof outage (or shell height equivalent to the volume contained under the roof)	ft	12, 14	---	2
H_S	tank shell height	ft	---	---	1
H_{VO}	vapor space outage (or height)	ft	11	---	---
I	daily total solar insolation on a horizontal surface	Btu/ft^2 day	---	4	---
K_E	vapor space expansion factor	dimensionless	4	---	---
K_P	working loss product factor	dimensionless	43	---	---
K_S	vented vapor saturation factor	dimensionless	5, 37	---	9
K_N	working loss turnover factor	dimensionless	39, 40	---	10
L_S	standing storage loss	lb/yr or bbl/yr	1, 6	2	---
L_T	total loss	lb/yr or bbl/yr	9, 10	---	---
L_W	working loss	lb/yr or bbl/yr	7, 8	3	---
M_V	stock vapor molecular weight	lb/lb-mole	---	6, 7	---
N	stock turnover rate	turnovers/yr	41	---	---
P_A	atmospheric pressure	psia	---	---	---
P_{BP}	breather vent pressure setting (always a positive value)	psig	---	---	---
P_{BV}	breather vent vacuum setting (always a negative value)	psig	---	---	---
ΔP_B	breather vent pressure setting range	psi	36	---	---
P_V	stock vapor pressure at the liquid surface temperature, T_L	psia	---	6, 7	5, 8
P_{VA}	stock vapor pressure at the daily average liquid surface temperature	psia	27	6, 7	5, 8
P_{VN}	stock vapor pressure at the daily minimum liquid surface temperature	psia	28	6, 7	5, 8
P_{VX}	stock vapor pressure at the daily maximum liquid surface temperature	psia	26	6, 7	5, 8
ΔP_V	stock daily vapor pressure range	psi	34	---	---
Q	stock annual net throughput (associated with increasing the stock liquid level in the tank)	bbl/yr	---	---	---
R	ideal gas constant (10.731)	$\frac{\text{psia ft}^3}{\text{lb-mole }^{\circ}R}$	---	---	---
R_R	tank dome roof radius	ft	---	---	1b
R_S	tank shell radius	ft	---	---	1
RVP	stock Reid vapor pressure	psi	---	---	---
S	stock ASTM-D86 distillation slope at 10 volume percent evaporated	$^{\circ}F$/vol.%	31	8	---
S_R	tank cone roof slope	ft/ft	---	---	1a
T_S	temperature at which 5 volume percent is evaporated	$^{\circ}F$	31	---	---
T_{1S}	temperature at which 15 volume percent is evaporated	$^{\circ}F$	31	---	---
T_A	ambient temperature	$^{\circ}R$	---	---	---
T_{AA}	daily average ambient temperature	$^{\circ}R$	18	---	---
T_{AN}	daily minimum ambient temperature	$^{\circ}R$	---	4	---
T_{AX}	daily maximum ambient temperature	$^{\circ}R$	---	4	---
ΔT_A	daily ambient temperature range	$^{\circ}R$	19	---	---
T_B	liquid bulk temperature	$^{\circ}R$	21	---	---
T_L	liquid surface temperature	$^{\circ}R$	---	---	---
T_{LA}	daily average liquid surface temperature	$^{\circ}R$	22	---	---
T_{LN}	daily minimum liquid surface temperature	$^{\circ}R$	25	---	---
T_{LX}	daily maximum liquid surface temperature	$^{\circ}R$	24	---	---
T_V	vapor temperature	$^{\circ}R$	---	---	---
ΔT_V	daily vapor temperature range	$^{\circ}R$	23	---	---
V_{LX}	tank maximum liquid volume (or tank liquid capacity)	ft^3	42	---	---

Table 1 - Nomenclature (Continued)

Symbol	Description	Units	Reference Information		
			Equations	Tables	Figures
V_V	tank vapor space volume	ft^3	2	...	...
W_L	stock liquid density	lb/gal	...	7	...
W_V	stock vapor density	lb/ft^3	3	...	...
W_{VC}	stock condensed vapor density at 60°F	lb/gal	38	6, 7	...
	Greek Symbol Notation				
α	tank paint solar absorptance	dimensionless	20	5	...
α_R	tank roof paint solar absorptance	dimensionless	...	5	...
α_S	tank shell paint solar absorptance	dimensionless	...	5	...
π	constant (3.14159)	dimensionless	...	...	...
	Function Notation				
exp()	exponential value of the quantity in parentheses				
ln()	natural logarithm value of the quantity in parentheses				
	Subscript Notation				
A	ambient, or atmospheric				
AA	ambient average				
AN	ambient minimum				
AX	ambient maximum				
B	breather, or liquid bulk				
BP	breather pressure				
BV	breather vacuum				
E	expansion				
L	liquid				
LA	liquid average				
LN	liquid minimum				
LX	liquid maximum				
N	turnover				
P	product				
R	roof				
RO	roof outage				
S	standing, or shell, or saturation				
T	total				
V	vapor				
VA	vapor average				
VC	vapor condensed				
VN	vapor minimum				
VO	vapor outage				
VX	vapor maximum				
W	working				
	Unit Notation				
Btu	British thermal unit				
lb	pound mass				
lb-mole	pound mole				
°R	degrees Rankine				
°F	degrees Fahrenheit				
	Conversion Relationships				
°R	= °F + 459.67				
psia	= psig + 14.696				

Table 2 - Summary of Procedure for Calculating Standing Storage Loss (L_S)

Standing Storage Loss Equations

$$L_S\ (lb/yr) = 365\ V_V\ W_V\ K_E\ K_S \quad (1)$$

$$L_S\ (bbl/yr) = \frac{L_S\ (lb/yr)}{42\ W_{VC}} \quad (6)$$

VARIABLE	DESCRIPTION	EQUATION	UNITS	SOURCE
V_V	Tank vapor space volume $= \frac{\pi}{4} D^2 H_{VO}$	(2)	ft^3	Calculate from Equation 2
D	Tank diameter		ft	User specified
H_{VO}	Vapor space outage $= H_S - H_L + H_{RO}$	(11)	ft	Calculate from Equation 11
H_S	Tank shell height		ft	User specified
H_L	Stock liquid height (or image)		ft	User specified
H_{RO}	Roof outage		ft	Calculate from Equation 12 for a cone roof Calculate from Equation 14 for a dome roof
W_V	Stock vapor density $= \frac{M_V P_{VA}}{R\ T_{LA}}$	(3)	lb/ft^3	Calculate from Equation 3
R	Ideal gas constant (10.731)		$\frac{psia\ ft^3}{lb\text{-}mole\ ^oR}$	
M_V	Stock vapor molecular weight		lb/lb-mole	User specified or Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks 64 for gasoline 50 for U.S. midcontinent crude oil stocks
P_{VA}	Stock vapor pressure at the daily average liquid surface temperature $= \exp[A - (B/T_{LA})]$	(27)	psia	Calculate from Equation 27 or Figure 5 for refined petroleum stocks Figure 8 for crude oil stocks
A	Constant in the vapor pressure equation		dimensionless	Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks Equation 29 or Figure 3 for refined petroleum stocks Equation 32 or Figure 6 for crude oil stocks
B	Constant in the vapor pressure equation		^oR	Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks Equation 30 or Figure 4 for refined petroleum stocks Equation 33 or Figure 7 for crude oil stocks
T_{LA}	Daily average liquid surface temperature $= 0.44T_{AA} + 0.56T_B + 0.0079\alpha I$	(22)	^oR	Calculate from Equation 22
T_{AA}	Daily average ambient temperature		^oR	User specified or Table 4 and Equation 18
T_B	Liquid bulk temperature		^oR	User specified or Calculate from Equation 21
α	Tank paint solar absorptance		dimensionless	User specified or Table 5 Calculate from Equation 20 for different color roof and shell
I	Daily total solar insolation on a horizontal surface		Btu/ft^2 day	User specified or Table 4

Table 2 - Summary of Procedure for Calculating Standing Storage Loss (L_S) (Continued)

Standing Storage Loss Equations

$$L_S\ (lb/yr) = 365\ V_V\ W_V\ K_E\ K_S \qquad (1)$$

$$L_S\ (bbl/yr) = \frac{L_S\ (lb/yr)}{42\ W_{VC}} \qquad (6)$$

VARIABLE	DESCRIPTION	EQUATION	UNITS	SOURCE
K_E	Vapor space expansion factor $= \frac{\Delta T_V}{T_{LA}} + \frac{\Delta P_V - \Delta P_B}{P_A - P_{VA}}$	(4)	dimensionless	Calculate from Equation 4
ΔT_V	Daily vapor temperature range $= 0.72\Delta T_A + 0.028\alpha I$	(23)	°R	Calculate from Equation 23
ΔT_A	Daily ambient temperature range		°R	User specified or Table 4 and Equation 19
α	Tank paint solar absorptance		dimensionless	Refer to source described above
I	Daily total solar insolation on a horizontal surface		Btu/ft^2 day	Refer to source described above
T_{LA}	Daily average liquid surface temperature		°R	Refer to source described above
ΔP_V	Stock daily vapor pressure range $= P_{VX} - P_{VN}$	(34)	psi	Calculate from Equation 34 or 35
P_{VX}	Stock vapor pressure at the daily maximum liquid surface temperature		psia	Calculate from Equation 26 for T_{LX} from Equation 24
P_{VN}	Stock vapor pressure at the daily minimum liquid surface temperature		psia	Calculate from Equation 28 for T_{LN} from Equation 25
ΔP_B	Breather vent pressure setting range $= P_{BP} - P_{BV}$	(36)	psi	Calculate from Equation 36
P_{BP}	Breather vent pressure setting		psig	User specified or typically 0.03
P_{BV}	Breather vent vacuum setting		psig	User specified or typically -0.03
P_A	Atmospheric pressure		psia	User specified or typically 14.7
P_{VA}	Stock vapor pressure at the daily average liquid surface temperature		psia	Refer to source described above
K_S	Vented vapor saturation factor $= \frac{1}{1 + 0.053 P_{VA} H_{VO}}$	(5)	dimensionless	Calculate from Equation 5
P_{VA}	Stock vapor pressure at the daily average liquid surface temperature		psia	Refer to source described above
H_{VO}	Vapor space outage		ft	Refer to source described above
W_{VC}	Stock condensed vapor density at 60°F		lb/gal	User specified or Table 6 for selected petroleum liquid stocks Table 7 selected petrochemical stocks Calculate from Equation 38 for refined petroleum stocks and crude oil stocks

Table 3 - Summary of Procedure for Calculating Working Loss (L_W)

Working Loss Equations

$$L_W \text{ (lb/yr)} = 0.0010\, M_V\, P_{VA}\, Q\, K_N\, K_P \quad (7)$$

$$L_W \text{ (bbl/yr)} = \frac{L_W \text{ (lb/yr)}}{42\, W_{VC}} \quad (8)$$

VARIABLE	DESCRIPTION	EQUATION	UNITS	SOURCE
M_V	Stock vapor molecular weight		lb/lb-mole	User specified or Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks 64 for gasoline 50 for U.S. midcontinent crude oil stocks
P_{VA}	Stock vapor pressure at the daily average liquid surface temperature $= \exp[A - (B/T_{LA})]$	(27)	psia	Calculate from Equation 27 or Figure 5 for refined petroleum stocks Figure 8 for crude oil stocks
A	Constant in the vapor pressure equation		dimensionless	Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks Equation 29 or Figure 3 for refined petroleum stocks Equation 32 or Figure 6 for crude oil stocks
B	Constant in the vapor pressure equation		°R	Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks Equation 30 or Figure 4 for refined petroleum stocks Equation 33 or Figure 7 for crude oil stocks
T_{LA}	Daily average liquid surface temperature		°R	Calculate from Equation 22
Q	= Stock annual net throughput		bbl/yr	User specified
K_N	Working loss turnover factor $= (180 + N)/6N$ (for $N > 36$) $= 1$ (for $N \leq 36$)	(39) (40)	dimensionless	Calculate from Equation 39 or 40
N	Stock turnover rate $= 5.614\, Q/V_{LX}$	(41)	turnover/yr	Calculate from Equation 41
V_{LX}	Tank maximum liquid volume $= \frac{\pi}{4} D^2 H_{LX}$	(42)	ft^3	Calculate from Equation 42
H_{LX}	Stock maximum liquid height		ft	User specified
K_P	Working loss product factor		dimensionless	0.75 for crude oil stocks 1.00 for refined petroleum stocks 1.00 for single-component petrochemical stocks
W_{VC}	Stock condensed vapor density at 60°F		lb/gal	User specified or Table 6 for selected petroleum liquid stocks Table 7 for selected petrochemical stocks Calculated from Equation 38 for refined petroleum stocks and crude oil stocks

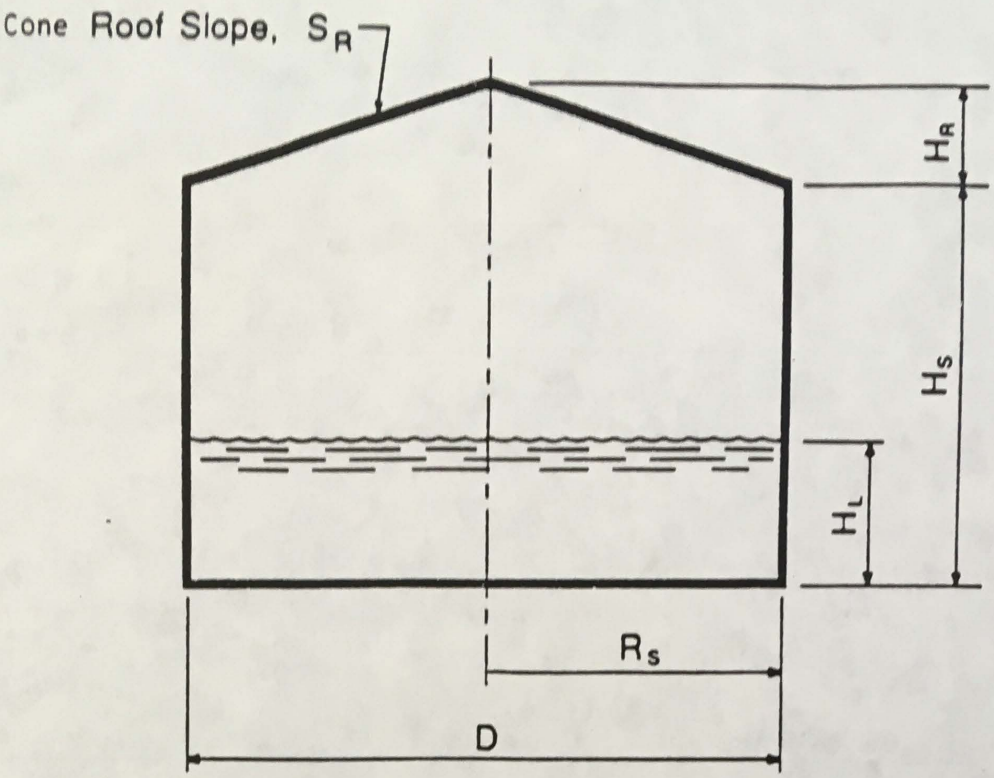


Figure 1a - Cone Roof

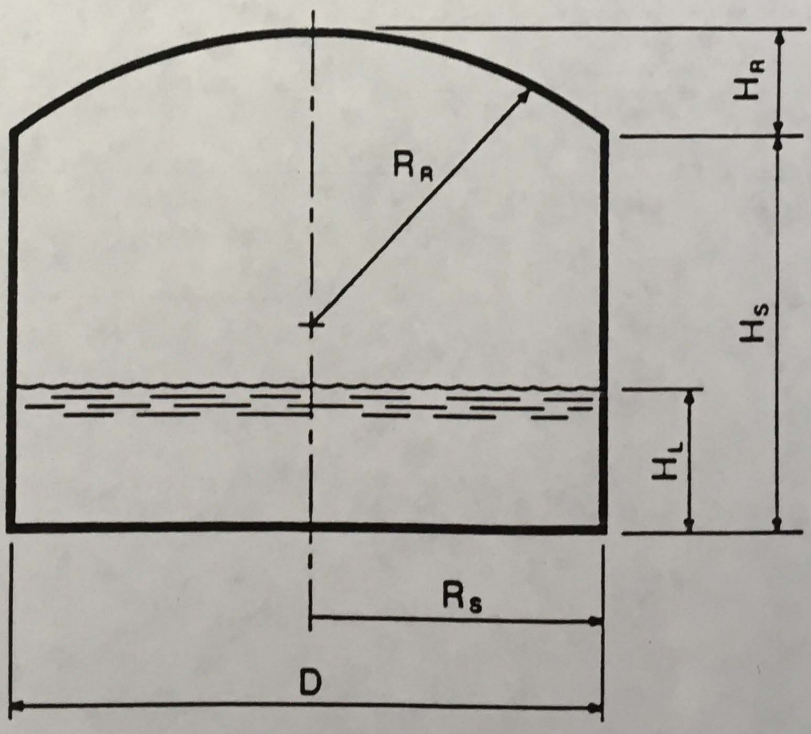


Figure 1b - Dome Roof

Figure 1 - Fixed-Roof Tank Geometry

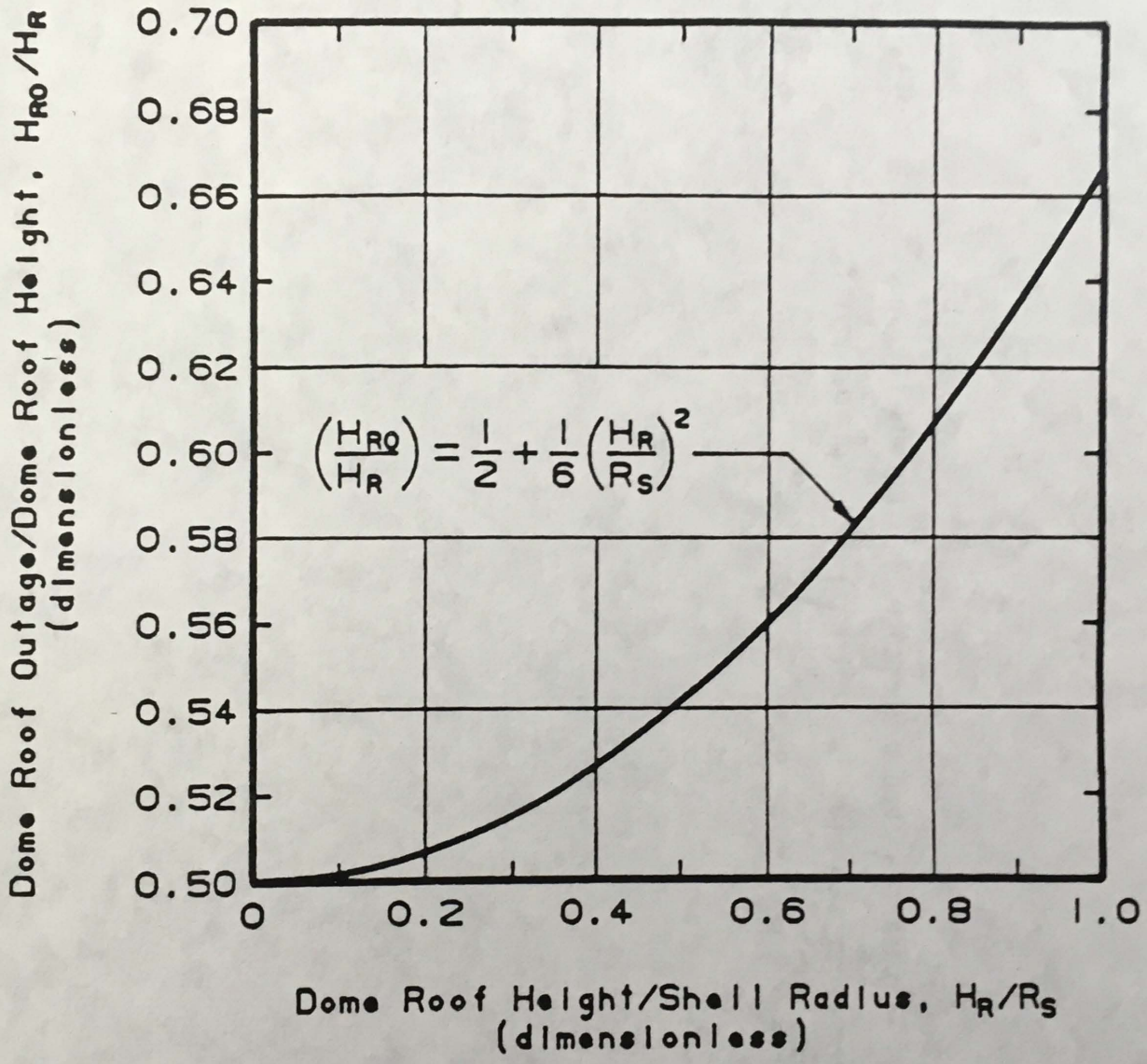
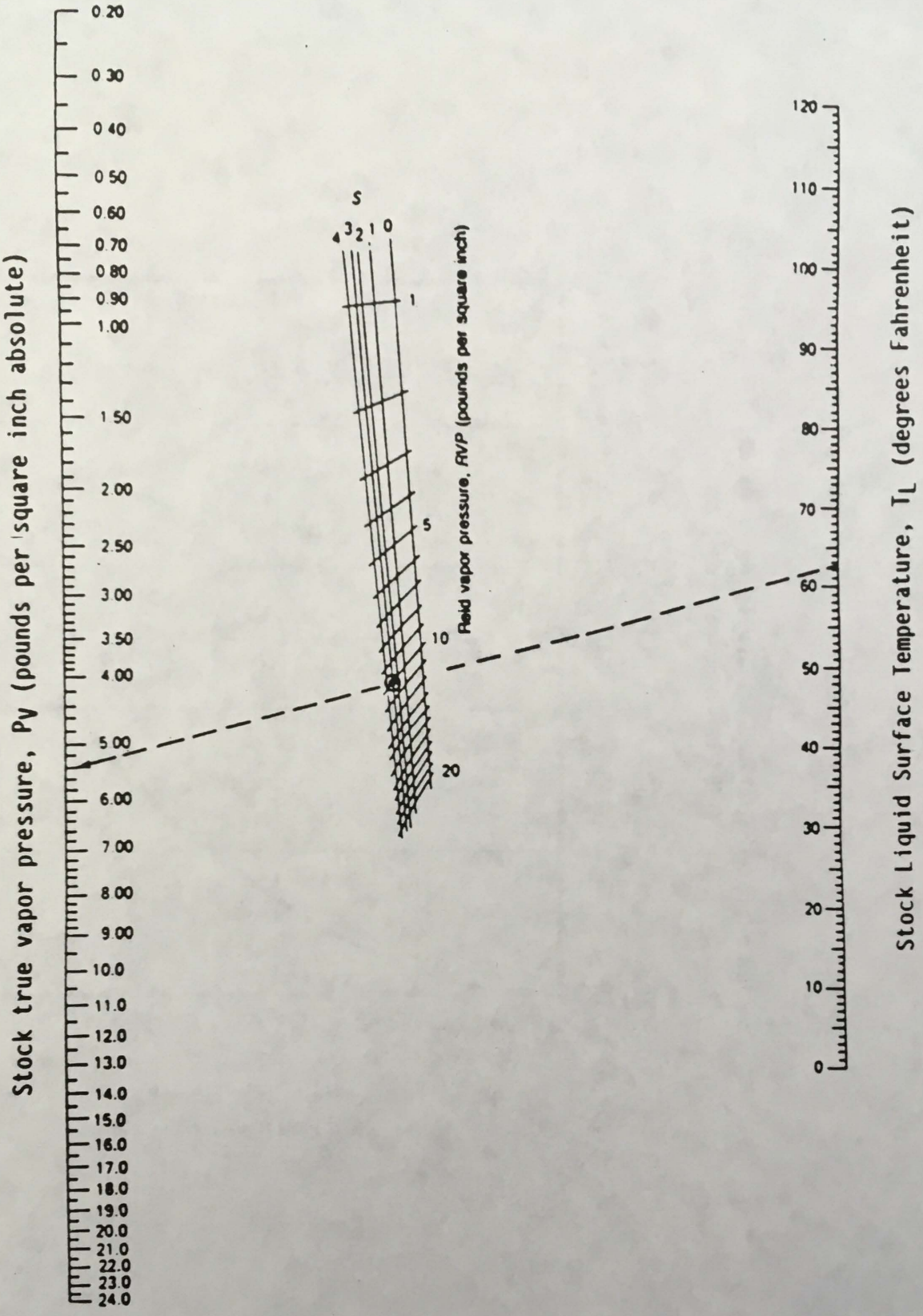


Figure 2 - Dome Roof Outage (H_{RO})

Figure 5 - True Vapor Pressure (P_V) of Refined Petroleum Stocks With a Reid Vapor Pressure of 1 to 20 Pounds Per Square Inch



Notes:

1. Dashed line illustrates sample problem for RVP = 10 pounds per square inch, gasoline stock (S=3.0) and degrees Fahrenheit.
2. See Section 2.2.2.3 for the equation of stock true vapor pressure, P_V.

Source: Nomograph drawn from data of the National Bureau of Standards.

Note: See Section 2.2.2.3 for the equation of stock true vapor pressure, Pv.

Figure 8 - True Vapor Pressure (Pv) of Crude Oil Stocks With a Reid Vapor Pressure of 2 to 15 Pounds Per Square Inch

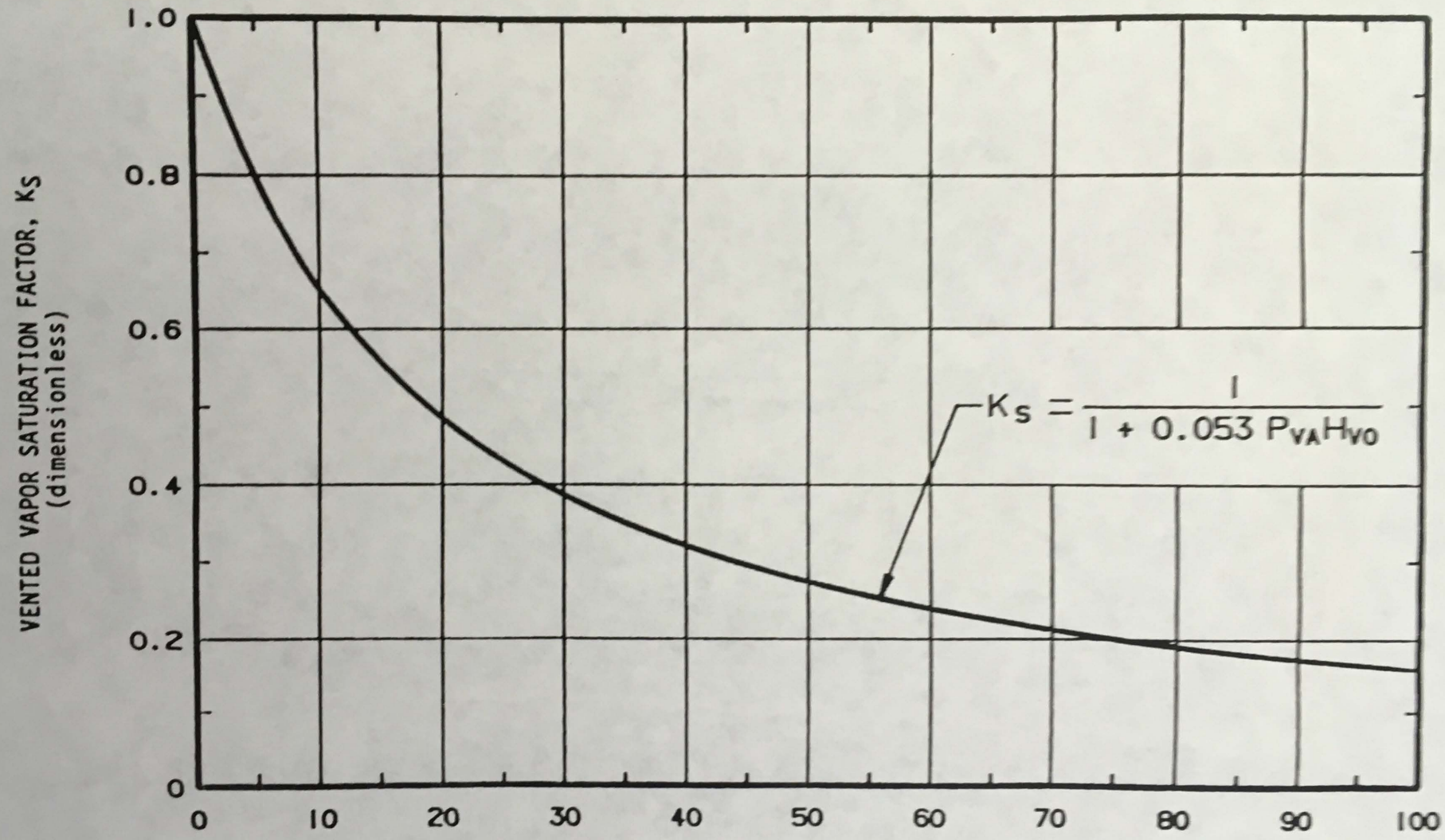


Figure 9 - ed Vapor Saturation Factor (K_S)

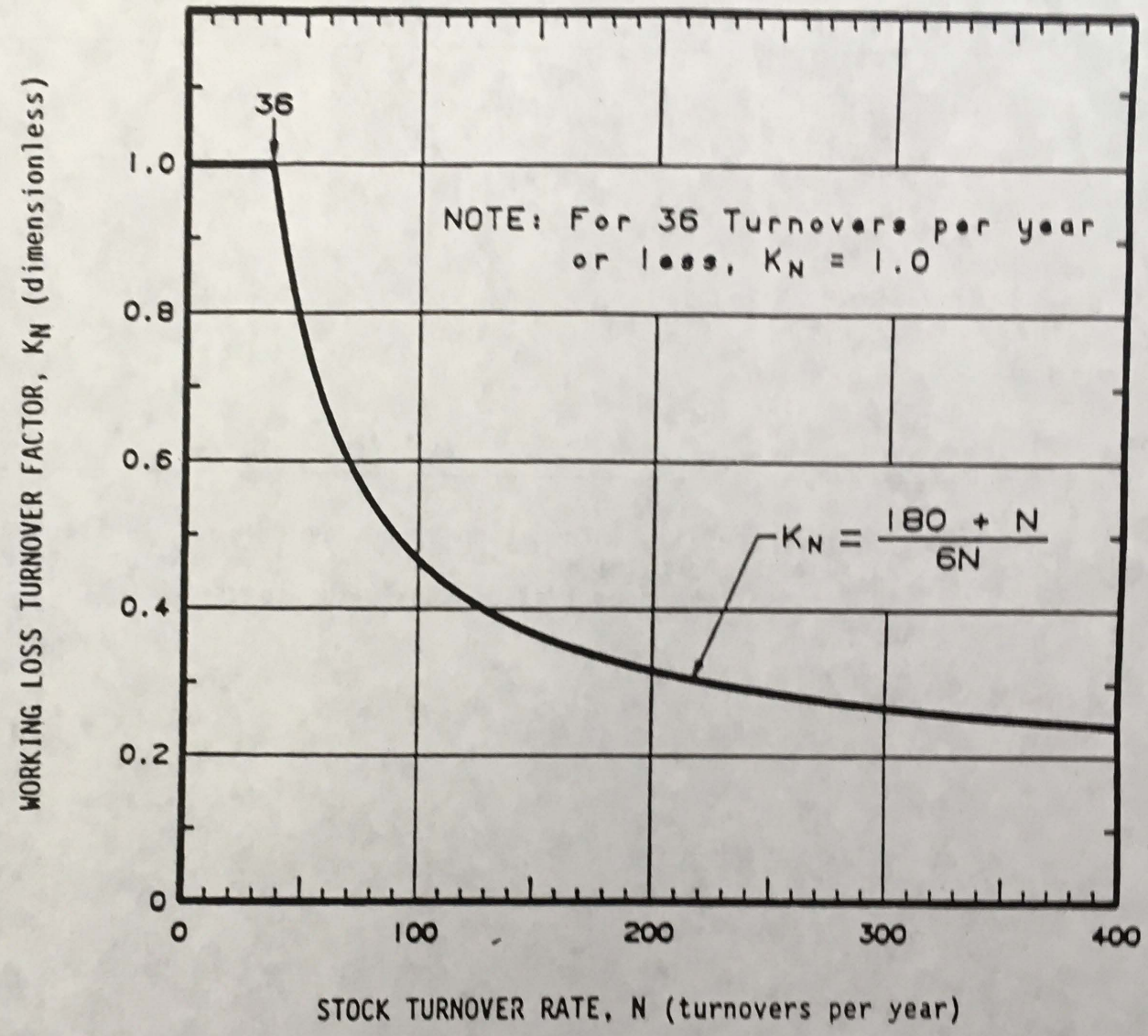


Figure 10 - Working Loss Factor (K_N)

Table 5 - Solar Absorptance (α) for Selected Tank Paints

Paint Color	Paint Shade or Type	Solar Absorptance, α (dimensionless) Paint Condition	
		Good	Poor
Aluminum	Specular	0.39	0.49
Aluminum	Diffuse	0.60	0.68
Gray	Light	0.54	0.63
Gray	Medium	0.68	0.74
Red	Primer	0.89	0.91
White	---	0.17	0.34

Notes: (1) If specific information is not available, a white shell and roof, with the paint in good condition, can be assumed to represent the most common or typical tank paint in use.

Table 6 - Properties (M_V, W_{VC}, P_V, A, B) of Selected Petroleum Liquids

Petroleum Liquid	Vapor Molecular Weight M_V (lb/lb-mole)	Condensed Vapor Density (at 60°F) W_{VC} (lb/gal)	Vapor Pressure (at 60°F) (Note 4) P_V (psia)	Vapor Pressure Equation Constants (Note 1) A (dimensionless)	B (°R)	Temperature Range For Constants A and B Minimum (°F)	Maximum (°F)
Refined Petroleum Stocks	---	---	---	Note 2	Note 2	---	---
Crude Oil Stocks	---	---	---	Note 2	Note 2	---	---
Jet Naphtha (JP-4)	80	5.4	1.27	11.368	5784.3	40	100
Jet Kerosene	130	6.1	0.00823	12.390	8933.0	40	100
Distillate Fuel Oil No. 2	130	6.1	0.00648	12.101	8907.0	40	100
Residual Oil No. 6	190	6.4	0.0000430	10.104	10475.5	40	100

Notes:

1. The vapor pressure equation is $P_V = \exp [A - (B/T_L)]$, where P_V is the vapor pressure in psia, T_L is the liquid surface temperature in °R, and exp is the exponential function.
2. The vapor pressure equation constants A and B are listed in Equations 29 and 30 for Refined Petroleum Stocks, and Equations 32 and 33 for Crude Oil Stocks. These constants are from Ref. 4.
3. Sources: The vapor pressure equation constants A and B were developed from a correlation of the vapor pressures given in Ref. 5 (except as indicated in Note 2). The other properties are also from Ref. 5.
4. Vapor pressure calculated at 60°F using constants A and B.

The emissions from external floating roof tanks is due to evaporation of the contained liquid. There are two mechanisms for emissions:

- Standing storage loss
- Withdrawal loss

Standing storage loss results from wind effects facilitating the evaporation of vapors between the floating roof seal (the rim seal) and the tank shell and around deck-fittings. The seal type, its condition, and whether a secondary seal is installed accordingly play an important role in determining the standing storage loss. Figure ST.1 illustrates the greater than one hundred fold difference in the emission levels as the seal characteristics are changed. Figure ST.2 shows examples of the typical primary seals used on external roof tanks and may be helpful in identifying the seals.

The withdrawal loss is associated with the vaporization of liquid from a wetted tank wall when it is exposed as the floating roof is lowered during stock removal. The condition of the internal wall of the tank can affect the clingage of hydrocarbon to the tank wall and hence the withdrawal loss.

The calculation procedures in this section determine the total emission based on the average molecular weight and vapor pressure of the contained liquid. To determine the emission of individual components of a contained mixture refer to the speciation procedures in sub-section 070 of this section.

Figure ST.1

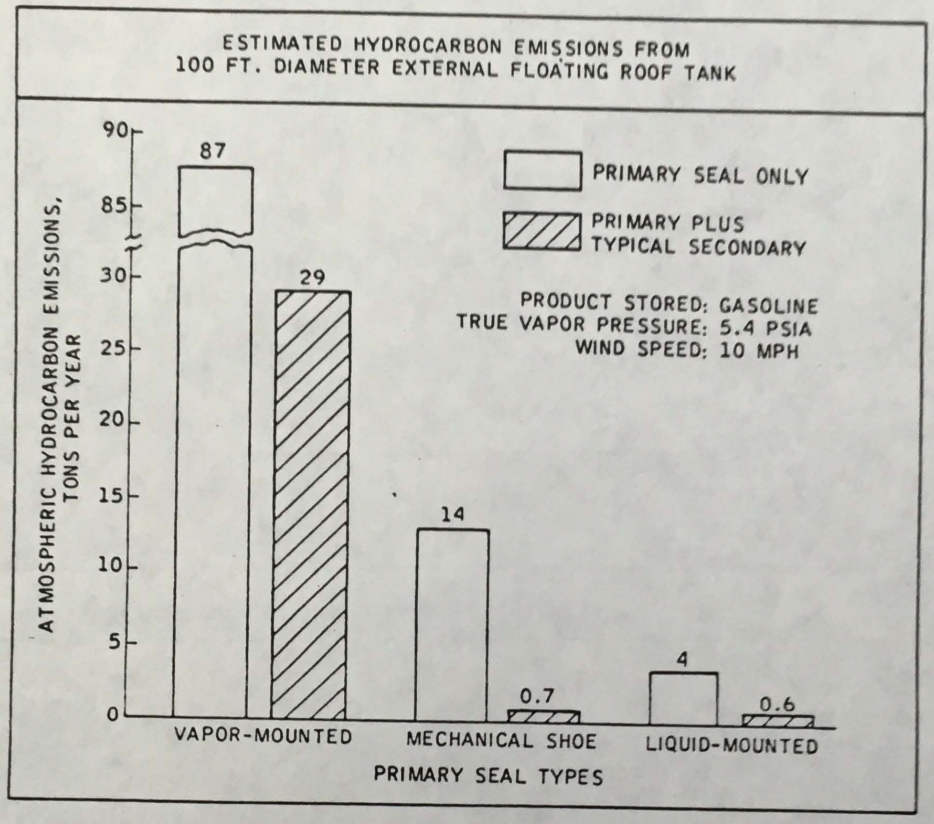
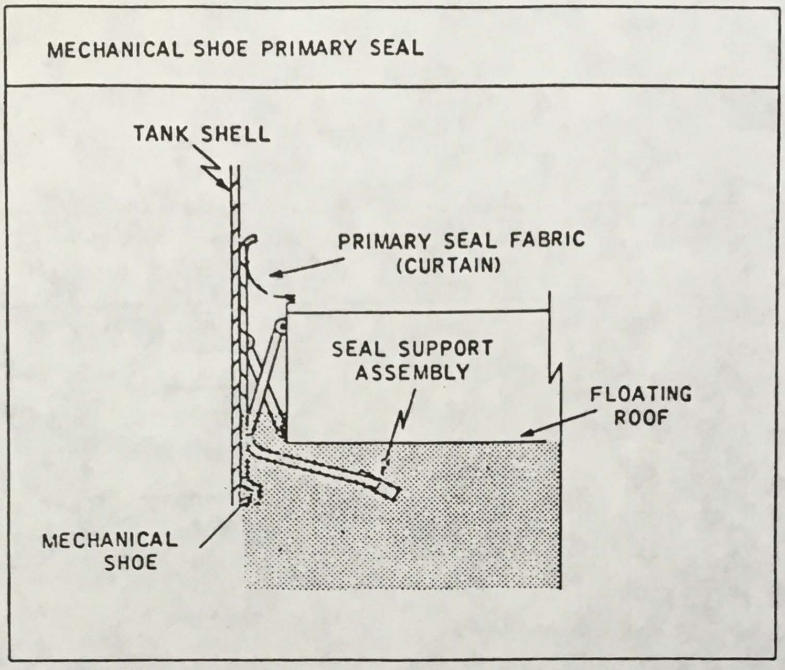
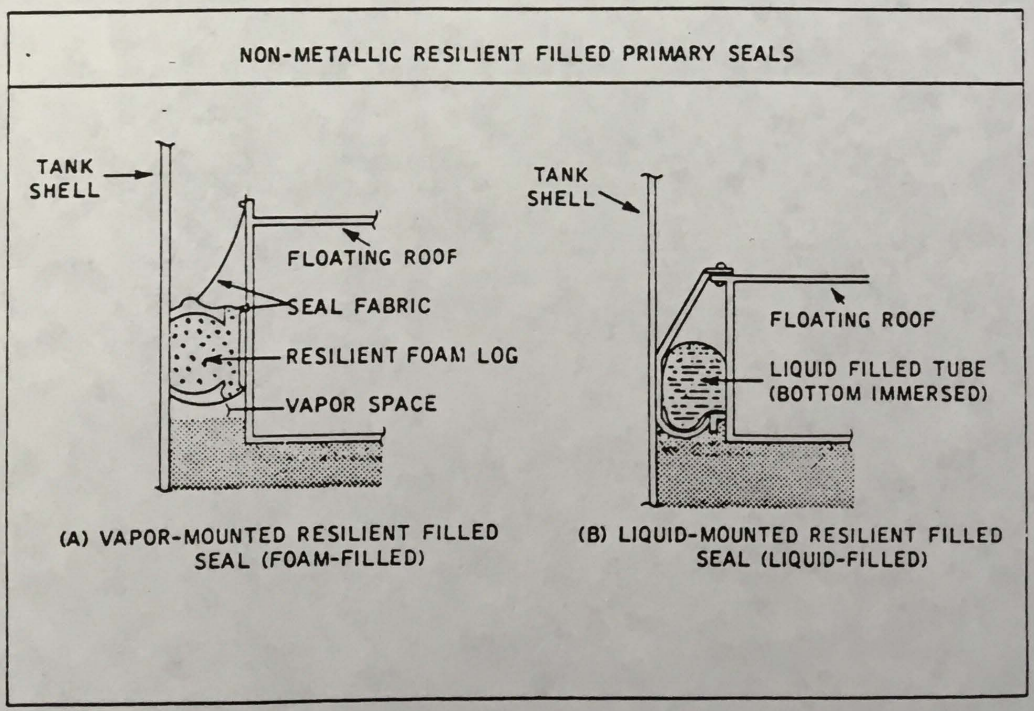

ESTIMATED HYDROCARBON EMISSIONS FROM
100 FT. DIAMETER EXTERNAL FLOATING ROOF TANK
ATMOSPHERIC HYDROCARBON EMISSIONS, TONS PER YEAR
90
85
30
25
20
15
10
5
0
87
29
14
0.7
4
0.6
PRIMARY SEAL ONLY
PRIMARY PLUS TYPICAL SECONDARY
PRODUCT STORED: GASOLINE
TRUE VAPOR PRESSURE: 5.4 PSIA
WIND SPEED: 10 MPH
VAPOR-MOUNTED
MECHANICAL SHOE
LIQUID-MOUNTED
PRIMARY SEAL TYPES

Figure ST.2



E-7-79-50



(A) VAPOR-MOUNTED RESILIENT FILLED SEAL (FOAM-FILLED)

(B) LIQUID-MOUNTED RESILIENT FILLED SEAL (LIQUID-FILLED)

E-7-79-56

Following is a list of data one needs and possible sources of information.

Data	Unit	Where
Composition of Liquid	mol fraction	8
Bulk Liquid Temperature	°F	
Tank diameter	ft.	2,6
Type of Roof Seal System		2,6,1
Condition of Roof Seal		6
Wind Speed	m/hr	3
Type and number of various deck fittings [a]		2,1
Atmospheric Pressure	psia	3,4
Throughput	bbl/yr	5

1) Maintenance Records
2) Facility construction drawings
3) Local meteorological station
4) Almanac
5) Facility Production Reports
6) Inspection Reports
7) Published Data
8) Laboratory Analysis
9) Process Design Data

Note [a] See 050-003 page 2 for a list of deck fittings and estimated emissions

The procedure to calculate the release is:

Step 1 - Gather the data identified in 050-001, page 1.

Step 2 - Based on the composition of liquid and the bulk liquid temperature, calculate the vapor pressure and the average molecular weight of the liquid in the tank.

Step 3 - Calculate the rim seal, deck fitting, and withdrawal losses from the equations on 050-002, page 1.

Step 4 - Add all the losses in Step 3 together to determine the annual emission.

Summary of Factors/Equations Used in API 2517, 3rd Edition

Type of Loss	Rim Seal (L_R)	Deck Fitting (L_F)	Withdrawal (L_W)
Equation	$K_s V^n P^* D M_v K_c$	$F_f P^* M_v K_c$	$\frac{(.943)\ QCW_L}{D}$
Factor Description			
K_s Seal Factor	See Section 050-004	-	-
V Wind Velocity, mi/hr	X	-	-
n Wind Exponent	See Section 050-004	-	-
P_A Atmos. Press., psia	X	X	-
p* Vap. Press. Func. (P True Vapor Pressure, psia)	$\frac{P/PA}{(1 + (1-P/PA)^{0.5})^2}$	X	-
D Tank Diam., ft.	X	-	X
M_v Vapor Molecular Weight	X	X	-
K_c Product Factor	Prod=1.0,Crude=0.4	X	-
F_f $\Sigma N_f K_f$	-	See Section 050-004	-
N_f Number of Fittings; K_f	Fitting Factors		
K_D (=0 for welded deck)	-	-	-
Q Throughout, bbl/yr	-	-	X
C Shell clingage factor	-	-	See Section 060-003
W_L liq density, lb/gal	-	-	X

x means parameter is included in above correlation.
- means parameter is not included in above correlation.

Example Problem (from API Publication 2517, 3rd Edition, Feb., 1989)

Estimate the total annual evaporative loss, in pounds per year and barrels per year, given the following information.

A welded, external floating-roof tank in good condition has the following characteristics:

a. A diameter of 100 feet.
b. A shell painted an aluminum color.
c. A pontoon floating roof.
d. A mechanical-shoe primary seal.
e. Typical roof fittings.

The motor gasoline stored in the tank has the following characteristics (no vapor or liquid composition is given):

a. A Reid vapor pressure of 10 pounds per square inch.
b. A liquid stock density of 6.1 pounds per gallon.
c. An average net throughput of 1.5 million barrels per year.

The ambient conditions are as follows:

a. An average annual ambient temperature of 60°F.
b. An atmospheric pressure of 14.7 pounds per square inch absolute.
c. An average annual wind speed of 10 miles per hour.

STANDING STORAGE LOSS

Calculate the standing storage loss from Equations 1 and 2:

$$L_s \text{ (pounds per year)} = [F_t D + F_j] P^* M_v K_c \quad (1)$$

$$L_s \text{ (barrels per year)} = \frac{L_s \text{ (pounds per year)}}{42 W_v} \quad (2)$$

The variables in Equations 1 and 2 can be determined as follows:

L_S = Deck fitting and rim seal loss (L_R + L_F)
F_t = $K_t V^n$
= 38 pound-moles per foot-year (from Equation 9 or from Figure 1 for an average-fitting primary seal only, with V = 10 miles per hour).

Note:	All references to Figures, Tables, and Equations refer to AP-42 and API reference in Section 050-004 unless indicated otherwise.

Where:

K_t = 1.2 pound-moles per (miles per hour)$^{1.5}$-foot-year (from Table 3 for a welded tank with a mechanical-shoe primary seal).
V = 10 miles per hour (given).
n = 1.5 (from Table 3 for a welded tank with a mechanical-shoe primary seal).
D = 100 feet (given).
F_f = $[(N_{f1}K_{f1}) + (N_{f2}K_{f2}) + \ldots + (N_{fx}K_{fx})]$
= 782 pound-moles per year (from Equation 10 or from Figure 14, with
V = 10 miles per hour).

Where:

$N_{f1}K_{f1}$ = $(1)[(0) + (0)(10)^0]$
= 0 pound-moles per year (for access hatches, from Equation 11 and Table 5).

$N_{f2}K_{f2}$ = $(1)[(0) + (67)(10)^{0.98}]$
640 pound-moles per year (for unslotted guide-pole wells, from Equation 11 and Table 5).

$N_{f3}K_{f3}$ = (not typically used)
= 0 pound-moles per year (for slotted guide-pole/sample wells, from Equation 11 and Table 5).

$N_{f4}K_{f4}$ = $(1)[(2.3) + (5.9)(10)^{1.0}]$
= 61.3 pound-moles per year (for gauge-float wells, from Equation 11 and Table 5).

$N_{f5}K_{f5}$ = $(1)(0.95) + (0.14)(10)^{1.0}]$
= 2.35 pound-moles per year (for gauge-hatch/sample wells, from Equation 11 and Table 5).

$N_{f6}K_{f6}$ = $(1)[(1.2) + (0.17)(10)^{1.0}]$
= 2.90 pound-moles per year (for vacuum breakers, from Equation 11 and Tables 5 and 6).

$N_{f7}K_{f7}$ = (not typically used)
= 0 pound-moles per year (for roof drains, from Equation 11 and Table 5 and 6).

$N_{f8}K_{f8}$ = $(17)[(1.5) + (0.20)(10)1.0] + (16)[(0.25) + (0.067)(10)^{1.0}]$
= 74.2 pound-moles per year (for roof legs, from Equation 11 and Tables 5 and 7).

$N_{f9}K_{f9}$ = $(1)[(0.71) + (0.10)(10)^{1.0}]$
= 1.71 pound-moles per year (for rim vents, from Equation 11 and Table 5).

$$P^* = \frac{P/P_a}{\{1 + [1 - (P/P_a)]^{0.5}\}^2}$$

$$= \frac{5.4/14.7}{\{1 + [1 - (5.4/14.7]^{0.5}\}^2}$$

$$= 0.114$$

Where:
Ta = 60°F (given).
Ts = 62.5°F (from Table 10 for an aluminum-colored tank).
RVP = Reid vapor pressure.
= 10 pounds per square inch (given).
P = 5.4 pounds per square inch absolute (for gasoline with RVP = 10 pounds per square inch and Ts = 62.5°F, from Figure 17).
P_a = 14.7 pounds per square inch absolute (given).
M_v = 64 pounds per pound-mole (for gasoline, from 2.2.2.4).
K_c = 1.0 (for refined stocks, from 2.2.2.5).
W_v = 5.1 pounds per gallon (from Equation 13).

To calculate the standing storage loss in pounds per year, substitute the values above into Equation 1:
L_s = $[(38)(100) + 782](0.114)(64)(1.0)$
= 33,400 pounds per year

To calculate the standing storage loss in barrels per year, substitute the values above into Equation 2:
L_s = 33,400/[(42)(5.1)]
= 156 barrels per year

Withdrawal Loss

Calculate the withdrawal loss from Equations 5 and 6:

$$L_w \text{ (pounds per year)} = \frac{0.943QCW_1}{D}$$

$$L_w \text{ (barrels per year)} = \frac{L_w \text{ (pounds per year)}}{42W_1}$$

The variable in Equations 5 and 6 can be determined as follows:

Q = 1.5 x 10^6 barrels per year (given).

C = 0.0015 barrel per 1000 square feet (for gasoline in a lightly rusted tank, from Table 11).
W_1 = 6.1 pounds per gallon (given).
D = 100 feet (given).

To calculate the withdrawal loss in pounds per year, substitute the values above into Equation 5:

L_w = [(0.943)(1.5 x 10^6)(0.0015)(6.1)]/100
= 129 pounds per year

To calculate withdrawal loss in barrels per year, substitute the values above into Equation 6:

L_w = 129/[(42)(6.1)]
= 0.5 barrel per year

Total Loss

Calculate the total loss from Equations 7 and 8:

L_t (pounds per year) = (L_s + L_w)(pounds per year)
= 33,400 + 129
= 33,500 pounds per year

L_t (barrels per year) = (L_s + L_w) (barrels per year)
= 156 + 0.5
= 157 barrels per year

The following tables and figures are required to estimate the emissions from external floating roof tanks. they are taken from API Publication 2517, 3rd Edition, February 1989.

Source: API Publication 2517, 3rd Ed., Feb., 1989

Table 3—Rim-Seal Loss Factors, K_r and n

Tank Construction and Rim-Seal System	Average-Fitting Seals		Tight-Fitting Seals[a]	
	K_r [lb-mole/(mi/hr)^n-ft-yr]	n (dimensionless)	K_r [lb-mole/(mi/hr)^n-ft-yr]	n (dimensionless)
Welded Tanks				
Mechanical-shoe seal				
Primary only	1.2[b]	1.5[b]	0.8	1.6
Shoe-mounted secondary	0.8	1.2	0.8	1.1
Rim-mounted secondary	0.2	1.0	0.2	0.9
Liquid-mounted resilient-filled seal				
Primary only	1.1	1.0	0.5	1.1
Weather shield	0.8	0.9	0.5	1.0
Rim-mounted secondary	0.7	0.4	0.5	0.5
Vapor-mounted resilient-filled seal				
Primary only	1.2	2.3	1.0	1.7
Weather shield	0.9	2.2	1.1	1.6
Rim-mounted secondary	0.2	2.6	0.4	1.5
Riveted Tanks				
Mechanical-shoe seal				
Primary only	1.3	1.5	[c]	[c]
Shoe-mounted secondary	1.4	1.2	[c]	[c]
Rim-mounted secondary	0.2	1.6	[c]	[c]

Note: The rim-seal loss factors K_r and n may only be used for wind speeds from 2 to 15 miles per hour.

[a] Criteria for seal tightness are defined in 2.2.2.1.

[b] If no specific information is available, a welded tank with an average-fitting mechanical-shoe primary seal only can be assumed to represent the most common or typical construction and rim-seal system in use.

[c] No evaporative-loss information is available for riveted tanks with consistently tight fitting rim-seal systems.

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2.2.2.2. Total Roof-Fitting Loss Factor

If information is available on the specific type and number of roof fittings, the total roof-fitting loss factor, F_f, can be estimated as follows:

$$F_f = [(N_{f1}K_{f1}) + (N_{f2}K_{f2}) + \ldots + (N_{fk}K_{fk})] \quad (10)$$

Where:

F_f = total roof-fitting loss factor, in pound-moles per year.
N_{fi} = number of roof fittings of a particular type (dimensionless).
K_{fi} = loss factor for a particular type of roof fitting, in pound-moles per year.
i = 1, 2, . . . , k (dimensionless).
k = total number of different types of roof fittings (dimensionless).

The loss factor for a particular type of roof fitting, K_{fi}, can be estimated as follows:

$$K_{fi} = K_{fai} + K_{fbi}V^{mi} \quad (11)$$

Where:

K_{fai} = loss factor for a particular type of roof fitting, in pound-moles per year.
K_{fbi} = loss factor for a particular type of roof fitting, in pound-moles per (miles per hour)^m - year.
m_i = loss factor for a particular type of roof fitting (dimensionless).
i = 1, 2, . . . , k (dimensionless).
V = average wind speed, in miles per hour.

The most common roof fittings are listed in Table 5, along with the associated roof-fitting-related loss factors, K_{fa}, K_{fb}, and m, for various types of construction details. These factors are applicable for typical roof-fitting conditions. The roof-fitting loss factors may only be used for wind speeds from 2 to 15 miles per hour. The loss factor for a particular type of roof fitting may be calculated using Equation 11 or read directly from Figures 5-13.

Since the number of each type of roof fitting can vary significantly from tank to tank, N_f values for each type of roof fitting should be determined for the tank under consideration. If this information is not available, typical N_f values are given in Tables 5, 6, and 7.

If no information is available about the specific type and number of roof fittings, a typical total roof-fitting loss factor, F_f, can be read from Figure 14 or 15. These figures show the total roof-fitting loss factor, F_f, as a function of tank diameter, D, for pontoon and double-deck floating roofs, respectively.

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Table 5—Roof-Fitting Loss Factors, K_a, K_b, and m, and Typical Number of Roof Fittings, N_f

Fitting Type and Construction Details	Loss Factors			Typical Number of Fittings, N_f
	K_a (lb-mole/yr)	K_b [lb-mole/(mi/hr)^m-yr]	m (dimensionless)	
Access hatch (24-inch-diameter well)				1
Bolted cover, gasketed	0	0	0[a]	
Unbolted cover, ungasketed	2.7	7.1	1.0	
Unbolted cover, gasketed	2.9	0.41	1.0	
Unslotted guide-pole well (8-inch-diameter unslotted pole, 21-inch-diameter well)				1
Ungasketed sliding cover	0	67	0.98[a]	
Gasketed sliding cover	0	3.0	1.4	
Slotted guide-pole/sample well (8-inch-diameter slotted pole, 21-inch-diameter well)				b
Ungasketed sliding cover, without float	0	310	1.2	
Ungasketed sliding cover, with float	0	29	2.0	
Gasketed sliding cover, without float	0	260	1.2	
Gasketed sliding cover, with float	0	8.5	2.4	
Gauge-float well (20-inch diameter)				1
Unbolted cover, ungasketed	2.3	5.9	1.0[a]	
Unbolted cover, gasketed	2.4	0.34	1.0	
Bolted cover, gasketed	0	0	0	
Gauge-hatch/sample well (8-inch diameter)				1
Weighted mechanical actuation, gasketed	0.95	0.14	1.0[a]	
Weighted mechanical actuation, ungasketed	0.91	2.4	1.0	
Vacuum breaker (10-inch-diameter well)				N_n (Table 6)
Weighted mechanical actuation, gasketed	1.2	0.17	1.0[a]	
Weighted mechanical actuation, ungasketed	1.1	3.0	1.0	
Roof drain (3-inch diameter)				N_n (Table 6)
Open	0	7.0	1.4[c]	
90% closed	0.51	0.81	1.0	
Roof leg (3-inch diameter)				N_n (Table 7)[d]
Adjustable, pontoon area	1.5	0.20	1.0[a]	
Adjustable, center area	0.25	0.067	1.0[a]	
Adjustable, double-deck roofs	0.25	0.067	1.0	
Fixed	0	0	0	
Roof leg (2½-inch diameter)				N_n (Table 7)[d]
Adjustable, pontoon area	1.7	0	0	
Adjustable, center area	0.41	0	0	
Adjustable, double-deck roofs	0.41	0	0	
Fixed	0	0	0	
Rim vent (6-inch diameter)				1[e]
Weighted mechanical actuation, gasketed	0.71	0.10	1.0[a]	
Weighted mechanical actuation, ungasketed	0.68	1.8	1.0	

Note: The roof-fitting loss factors, K_a, K_b, and m, may only be used for wind speeds from 2 to 15 miles per hour.

[a] If no specific information is available, this value can be assumed to represent the most common or typical roof fittings currently in use.

[b] A slotted guide-pole/sample well is an optional fitting and is not typically used.

[c] Roof drains that drain excess rainwater into the product are not used on pontoon floating roofs. They are, however, used on double-deck floating roofs and are typically left open.

[d] The most common roof leg diameter is 3 inches. The loss factors for 2½-inch-diameter roof legs are provided for use if this smaller size roof leg is used on a particular floating roof.

[e] Rim vents are used only with mechanical-shoe primary seals.

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Table 6—Typical Number of Vacuum Breakers, N_s, and Roof Drains, N_r

Tank Diameter, D (feet)[a]	Number of Vacuum Breakers, N_s		Number of Roof Drains, N_r (Double-Deck Roof)[b]
	Pontoon Roof	Double-Deck Roof	
50	1	1	1
100	1	1	1
150	2	2	2
200	3	2	3
250	4	3	5
300	5	3	7
350	6	4	—
400	7	4	—

Note: This table was derived from a survey of users and manufacturers. The actual number of vacuum breakers may vary greatly depending on throughput and manufacturing prerogatives. The actual number of roof drains may also vary greatly depending on the design rainfall and manufacturing prerogatives. For tanks more than 300 feet in diameter, actual tank data or the manufacturer's recommendations may be needed for the number of roof drains. This table should not supersede information based on actual tank data.

[a] If the actual diameter is between the diameters listed, the closest diameter listed should be used. If the actual diameter is midway between the diameters listed, the next larger diameter should be used.

[b] Roof drains that drain excess rainwater into the product are not used on pontoon floating roofs. They are, however, used on double-deck floating roofs and are typically left open.

Table 7—Typical Number of Roof Legs, N_l

Tank Diameter, D (feet)[a]	Pontoon Roof		Num... Legs on Double-Dec... Roof
	Number of Pontoon Legs	Number of Center Legs	
30	4	2	6
40	4	4	7
50	6	6	8
60	9	7	10
70	13	9	13
80	15	10	16
90	16	12	20
100	17	16	25
110	18	20	29
120	19	24	34
130	20	28	40
140	21	33	46
150	23	38	52
160	26	42	58
170	27	49	66
180	28	56	74
190	29	62	82
200	30	69	90
210	31	77	98
220	32	83	107
230	33	92	115
240	34	101	127
250	35	109	138
260	36	118	149
270	36	128	162
280	37	138	173
290	38	148	[illegible]
300	38	156	[illegible]
310	39	168	213
320	39	179	226
330	40	190	240
340	41	202	255
350	42	213	270
360	44	226	285
370	45	238	300
380	46	252	315
390	47	266	330
400	48	281	345

Note: This table was derived from a survey of users and manufa... turers. The actual number of roof legs may vary greatly depending ... age, style of floating roof, loading specifications, and manufacturi... prerogatives. This table should not supersede information based ... actual tank data.

[a] If the actual diameter is between the diameters listed, the close... diameter listed should be used. If the actual diameter is midw... between the diameters listed, the next larger diameter should be use...

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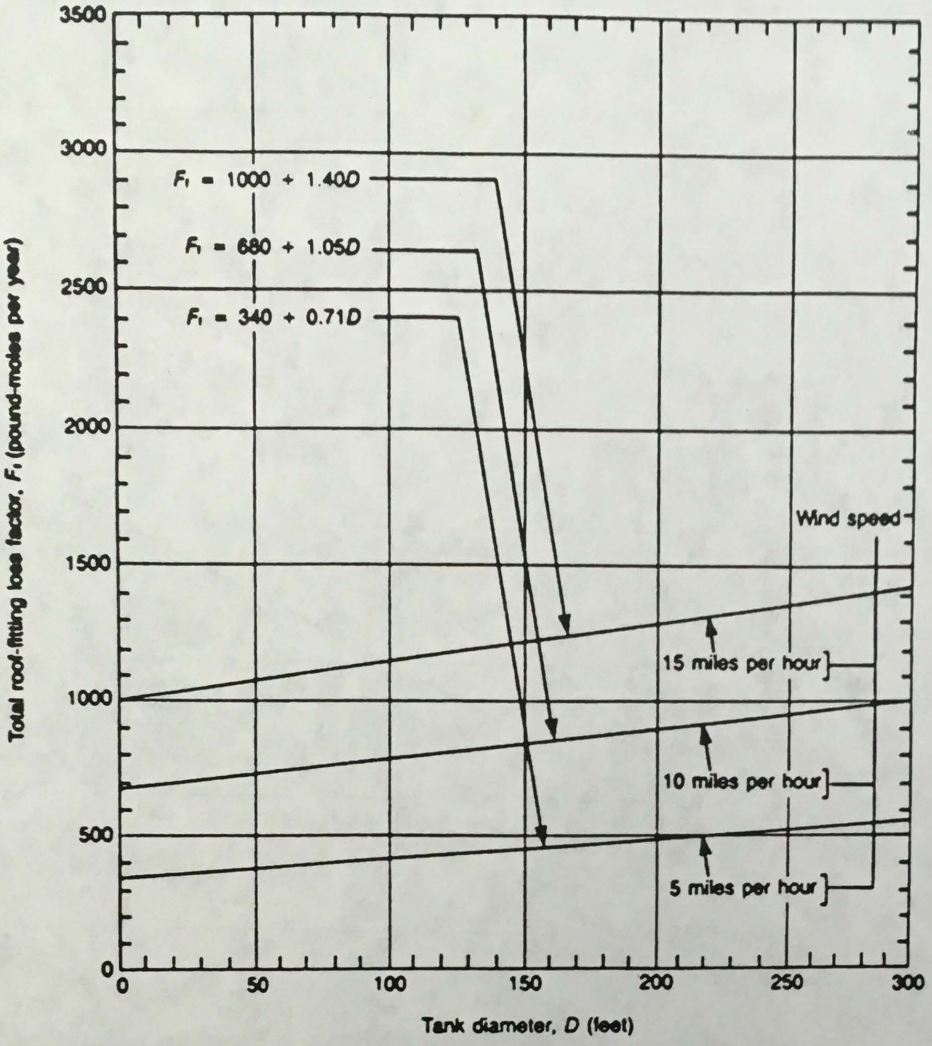


Figure 14—Total Roof-Fitting Loss Factor for Typical Fittings on Pontoon Floating Roofs

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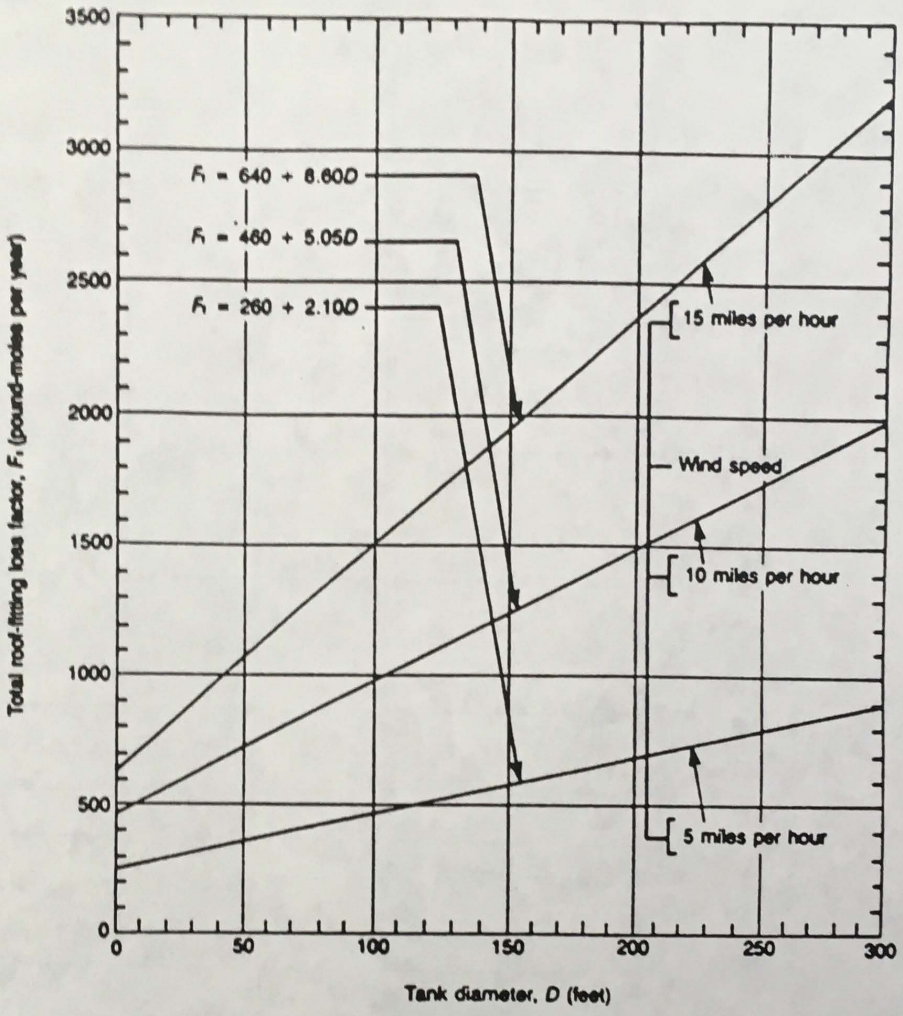


Figure 15—Total Roof-Fitting Loss Factor for Typical Fittings on Double-Deck Floating Roofs

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ROOF LANDINGS / CHANGE OF SERVICE

A roof landing occurs when a external floating roof tank's material is lowered to a level which causes the roof legs to touch the bottom of the tank and a vapor space is created between the roof and the liquid level. In this situation the roof is no longer floating, but is supported by the roof legs. Air is drawn into the vapor space, saturated with hydrocarbons and is emitted when the liquid level rises or the tank is gas freed.

There is no standard method for estimating the emissions from landing a floating roof. Engineering judgement and assumptions are used to make a estimate of these emissions.

Floating roofs have either fixed roof legs (typically 10 ft in height) or adjustable roof legs (typically settings are 10 ft when tank is out of service and 4 ft for normal operations). The leg heights are needed to determine the volume of the vapor space in a tank when the roof is landed.

As an example, an external floating roof containing gasoline has a diameter of 106 ft and a height of 44 ft. The following volumes can be calculated:

Standard equation: $\text{Volume} = (\text{pi} \times d^2)/4 \times h$

For normal operations (4 ft legs)

$$V(op) = (3.14 \times 106^2)/4 \times 4$$
$$= 35{,}281 \text{ ft}^3$$

For maintenance (10 ft legs)

$$V(mt) = (3.14 \times 106^2)/4 \times 10$$
$$= 88{,}203 \text{ ft}^3$$

The ideal gas law defines the relationship between the moles of vapor and the volume at standard conditions. Using for this example a temperature of 49.8°F or 509.47°R, the volume for one lb-mole of gas can be determined as follows:

Using ideal gas law $PV_s = nrT_s$

$$V_1 = T_1 / T_s \times V_s$$
$$= 509.47/492 \times 359 \text{ ft}^3 \text{ per lb-mole}$$
$$= 371.75 \text{ ft}^3/\text{lb-mole}$$

Therefore the number of moles (n) can be determined:

$$n(op) = V(op) / V_1$$
$$= 35{,}281\ ft^3 / 371.75\ ft^3/lb\text{-}mole$$
$$= 94.9\ lb\text{-}moles$$

$$n(mt) = V(mt) / V_1$$
$$= 88{,}203\ ft^3 / 371.75\ ft^3/lb\text{-}mole$$
$$= 237.3\ lb\text{-}moles$$

A determination of the concentration of hydrocarbon in the vapor space is needed. If the assumption that true vapor pressure (TVP) of the material store is equal to the partial pressure of hydrocarbon in the vapor space the mole fraction can be calculated. For this example the TVP of gasoline is 5.17 psia, the local atmospheric pressure (ATM) is 14.75 psia, and the molecular weight of the gasoline is 64 lbs/lb-mole.

Estimate of mole fraction = 5.17/14.75 = 0.35

Therefore, calculate release (r) as follows:

release = moles of vapor x mole fraction x molecular weight

r(op) = 94.9 lb-moles x 0.35 x 64 lbs/lb-mole
= 2,126 lbs

r(mt) = 237.3 lb-moles x 0.35 x 64 lbs/lb-mole
= 5,316 lbs

The estimate assumes the vapor is completely saturated, the tank is completely emptied after the roof is landed, and that 100% of the vapor space is emitted when the tank is filled. The estimate may significantly overstate the emissions of roof landings during normal operations but may be reasonable for tank maintenance roof landings. To conduct a maintenance landing the vapor space is air purged (gas freed) to allow entry to the tank for maintenance work. For tanks with multiple rim seals (primary plus secondary) the emissions from roof landing may be a significant fraction of the total emissions.

The emission from internal floating roof tanks is due to evaporation of the contained liquid. There are two mechanisms for emissions:

- Standing storage loss
- Withdrawal loss

Standing storage loss results from evaporation of vapors between the floating roof seal (the rim seal) and the tank shell, around deck-fittings, and at deck seams. The seal type, its condition, and whether a secondary seal is installed play an important role in determining the standing storage loss.

The withdrawal loss is associated with the vaporization of liquid from a wetted tank wall when it is exposed as the floating roof is lowered during stock removal. The condition of the internal wall of the tank can affect the clingage of hydrocarbon to the tank wall and hence the withdrawal loss.

The calculation procedures in this section determine the total emission based on the average molecular weight and vapor pressure of the contained liquid. To determine the emission of individual components of a mixture refer to the speciation procedures in sub-section 070 of this section.Following is a list of data one needs and possible sources of information.

Following is a list of data one needs and possible sources of information.

Data	Unit	Where
Type of floating roof (seam construction)		2
Type of fixed roof (column or self-supported)		2
Composition of Liquid	mol fraction	8
Bulk Liquid Temperature	°F	
Tank diameter	ft.	2,6
Type of Roof Seal System		2,6,1
Condition of Roof Seal		6
Type and number of various deck fittings [a]		2,1
Atmospheric Pressure	psia	3,4
Throughput	bbl/yr	5

1) Maintenance Records
2) Facility construction drawings
3) Local meteorological station
4) Almanac
5) Facility Production Records
6) Inspection Reports
7) Published Data
8) Laboratory Analysis
9) Process Design Data

Note [a] See 050-003 page 2 for a list of deck fittings.

The procedure to calculate the release is:

Step 1 - Gather the data identified in 060-000, page 2.

Step 2 - Based on the composition of liquid and the bulk liquid temperature, calculate the vapor pressure and the average molecular weight of the liquid in the tank.

Step 3 - Determine the shell clingage and product factors from Table in Section 050-004.

Step 4 - Calculate the rim seal, deck fitting, and withdrawal losses from the equations on page 060-002.

Step 5 - Add all the losses in Step 3 together to determine the annual emission.

Summary of Factors/Equations Used in AP-42, 4th Edition

Type of Loss	Rim Seal (L_R)	Deck Fitting (L_F)	Deck Seam(L_D)	Withdrawal (L_W)
Equation	$K_s V^n P^* D M_v K_c$	$F_f P^* M_v K_c$	$K_D S_D D^2 P^* M_v K_c$	$\frac{(.943)\ QCW_L}{D}\left[\frac{1 + N_c F_c}{D}\right]$
Factor Description				
K_s Seal Factor	Section 060-004	-	-	-
V Wind Velocity, mi/hr	X	-	-	-
n Wind Exponent	Section 060-004	-	-	-
P_A Atmos. Press., psia	X	X	X	
P* Vap. Press. Func. (P True Vapor Pressure, psia)	$\frac{P/PA}{(1 + (1-P/PA)^{0.5})^2}$	X	X	-
D Tank Diam., ft.	X	-	X	X
M_v Vapor Molecular Wght	X	X	X	-
K_c Product Factor	Prod=1.0,Crude=0.4	X	X	-
F_F $\Sigma N_6 K_6$	-	Section 060-004	-	-
N_6 Number of Fittings; K_6				
K_D (=0 for welded deck)	-	-	0.34 (Bolted deck)	-
S_D Lseam/Adeck	-	-	Section 060-004	-
Q Throughout, bbl/yr	-	-	-	X
C Shell clingage factor	-	-	-	Section 060-004
W_L liq density, lb/gal	-	-	-	X
N_c No. Columns	-	-	-	X
F_c Effective Col. Diam.	-	-	-	Section 060-004

X means parameter is included in above correlation.
- means parameter is not included in above correlation.

SAMPLE PROBLEM (from API Publication 2519, 3rd Edition, June, 1983)

Estimate the total annual evaporative loss, in pounds per year and barrels per year, given the following information:

Tank description: Freely vented internal floating-roof tank, with a column-supported fixed roof, in good condition; floating deck with bolted seams; built-up columns; typical deck fittings; vapor-mounted primary seal; 100-ft diameter; tank shell painted aluminum color.

Stored product: Motor gasoline; 10 psi Reid vapor pressure; 6.1 lb/gal average liquid stock density; no vapor or liquid compostion given; 1.5 million bbl/yr average annual net throughput.

Ambient conditions: 60°F average annual ambient temperature; 14.7 psia atmospheric pressure.

Note: All references to tables, figures, and equations refer to AP-42 and API reference material in Section 100-003, unless indicated otherwise

Standing Storage Loss

Calculate the standing storage loss from Equations 1 and 2.

$$L_s \text{ (lb/yr)} = [(K_r D) + (F_f) + (F_d)]\, P^* M_v K_c \qquad (1)$$

$$L_s \text{(bbl/yr)} = \frac{L_s \text{ (lb/yr)}}{(42) W_v} \qquad (2)$$

The variables in Equations 1 and 2 can be determined as follows:

L_s = Rim seal, deck fitting, and deck seam loss

K_r = 6.7 lb-mole/ft yr (from Table 4.3-4 for a vapor-mounted primary seal only.

D = 100 ft (given)

F_f = $[(N_{f1}K_{f1}) + (N_{f2}K_{f2}) + \ldots + (N_{fn}K_{fn})]$.
= $[(1)(25) + (6)(47) + (32)(7.9) + (1)(28) + (1)(76) + (1)(12) + (80)(1.2) + (1)(0.7)]$.
= 773 lb-mole/yr (From Tables 4.3-6 and 4.3-7, using the most common/typical values. For this case F_f could also be approximated from Figure 4.3-10 for a 100-foot diameter bolted deck.)

F_d = $K_d S_d D^2 = (0.34)(0.20)(100^2)$.
= 680 lb-mole/yr
K_d = 0.34 lb-mole/ft yr (for a bolted deck; 0 for a welded deck).
S_d = 0.20 ft/ft^2 (from Table 4.3-8, using the most common/typical value).

$$P^* = \frac{\frac{5.4}{14.7}}{[1 + (1 - \frac{5.4}{14.7})^{0.5}]^2}$$

= 0.114
T_a = 60°F (given).
T_s = 62.5°F (from Table 4.3-3 for an aluminum color tank).
RVP = 10 psi (given).
P = 5.4 psia
P_a = 14.7 psia (given).
M_v = 64 lb/lb-mole (for gasoline).
K_c = 1.0 (for refined and single component stocks, 0.4 for crude oils).
W_v = (0.08) Mv = 5.1 lb/gal (developed primarily for gasoline).

To calculate standing storage loss in lb/yr, substitute the above values into Equation 1:

L_s(lb/yr) = [(6.7)(100) + (773) + (680)](0.114)(64)(1.0)
= 15,490 lb/yr

To calculate standing storage loss in bbl/yr, substitute the above values into Equation 2:

L_s (bbl/yr) = $\frac{(15,490)}{(42)(5.1)}$ = 72 bbl/yr

Withdrawal Loss

Calculate the withdrawal loss from Equations 6 and 7:

$$L_w(lb/yr) = \frac{(0.943)QCW_l}{D}\left[1 + \frac{N_c F_c}{D}\right]$$

$$L_w(bbl/yr) = \frac{L_w(lb/yr)}{(42)\ W_l}$$

The variables in Equations 6 and 7 can be determined as follows:

Q = 1.5 x 106 bbl/yr (given).
C = 0.0015 bbl/1000 ft2 (from Table 4.3-5, for gasoline in a lightly rusted tank).
W_l = 6.1 lb/gal (given).
D = 100 ft (given).

N_c = 6 (from Table 4.3-6 for 100 ft diameter tank).
F_c = $\frac{\text{Column perimeter (ft)}}{3.14}$ = 1.1 ft

where Fc = 1.1 ft for 9-inch by 7-inch built-up columns.
0.7 ft for 8-inch diameter pipe columns.
1.0 ft an approximate value for use when no column construction details are known.

To calculate withdrawal loss in lb/yr, substitute the above values into Equation 6:

L_w (lb/yr)

$$= \frac{(0.943)(1.5 \times 106)(0.0015)(6.1)}{100}\left[\frac{1 + (6)(1.1)}{100}\right]$$

= 138 lb/yr

To calculate withdrawal loss in bbl/yr, substitute the above values in Equation 7:

$$L_w(\text{bbl/yr}) = \frac{(138)}{(42)(6.1)} = 0.5 \text{ bbl/yr}$$

Total Loss

Calculate the total loss from Equations 8 and 9:

$$Lt(\text{lb/yr}) = Ls(\text{lb/yr}) + Lw(\text{lb/yr})$$

$$= (15{,}490) + (138) = 15{,}630 \text{ lb/yr}$$

$$Lt(\text{bbl/yr}) = Ls(\text{bbl/yr}) + Lw(\text{bbl/yr})$$

$$= (72) + (0.5) = 73 \text{ bbl/yr}$$

The following tables and figures are required to estimate the emissions from internal floating roof tanks. They are taken from AP-42, September 1985.

TABLE 4.3-4. SEAL RELATED FACTORS FOR FLOATING ROOF TANKS[a]

Tank and seal type	Welded Tank K_S	Welded Tank n	Riveted Tank K_S	Riveted Tank n
Internal floating roof tanks[d]				
Liquid mounted resilient seal				
Primary seal only	3.0	0	NA[c]	NA
With rim mounted secondary seal[e]	1.6	0	NA	NA
Vapor mounted resilient seal				
Primary seal only	6.7	0	NA	NA
With rim mounted secondary seal[e]	2.5	0	NA	NA

[a]Based on emissions from tank seal systems in reasonably good working condition, no visible holes, tears, or unusually large gaps between the seals and the tank wall. The applicability of K_s decreases in cases where the actual gaps exceed the gaps assumed during development of the correlation.

[b]~~Reference 5.~~

[c]NA = Not Applicable.

[d]Reference 6.

[e]If tank specific information is not available about the secondary seal on an internal floating roof tank, then assume only a primary seal is present.

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TABLE 4.3-5. AVERAGE CLINGAGE FACTORS (C) (bbl/1,000 ft^2)[a]

Liquid	Shell condition		
	Light rust[b]	Dense rust	Gunite lined
Gasoline	0.0015	0.0075	0.15
Single component stocks	0.0015	0.0075	0.15
Crude oil	0.0060	0.030	0.60

[a]Reference 5.
[b]If no specific information is available, these values can be assumed to represent the most common condition of tanks currently in use.

TABLE 4.3-6. TYPICAL NUMBER OF COLUMNS AS A FUNCTION OF TANK DIAMETER FOR INTERNAL FLOATING ROOF TANKS WITH COLUMN SUPPORTED FIXED ROOFS[a]

Tank diameter range D (ft)	Typical number of columns, N_C
$0 < D \leq 85$	1
$85 < D \leq 100$	6
$100 < D \leq 120$	7
$120 < D \leq 135$	8
$135 < D \leq 150$	9
$150 < D \leq 170$	16
$170 < D \leq 190$	19
$190 < D \leq 220$	22
$220 < D \leq 235$	31
$235 < D \leq 270$	37
$270 < D \leq 275$	43
$275 < D \leq 290$	49
$290 < D \leq 330$	61
$330 < D \leq 360$	71
$360 < D \leq 400$	81

[a]Reference 1. This table was derived from a survey of users and manufacturers. The actual number of columns in a particular tank may vary greatly with age, fixed roof style, loading specifications, and manufacturing perogatives. Data in this table should not supersede information on actual tanks.

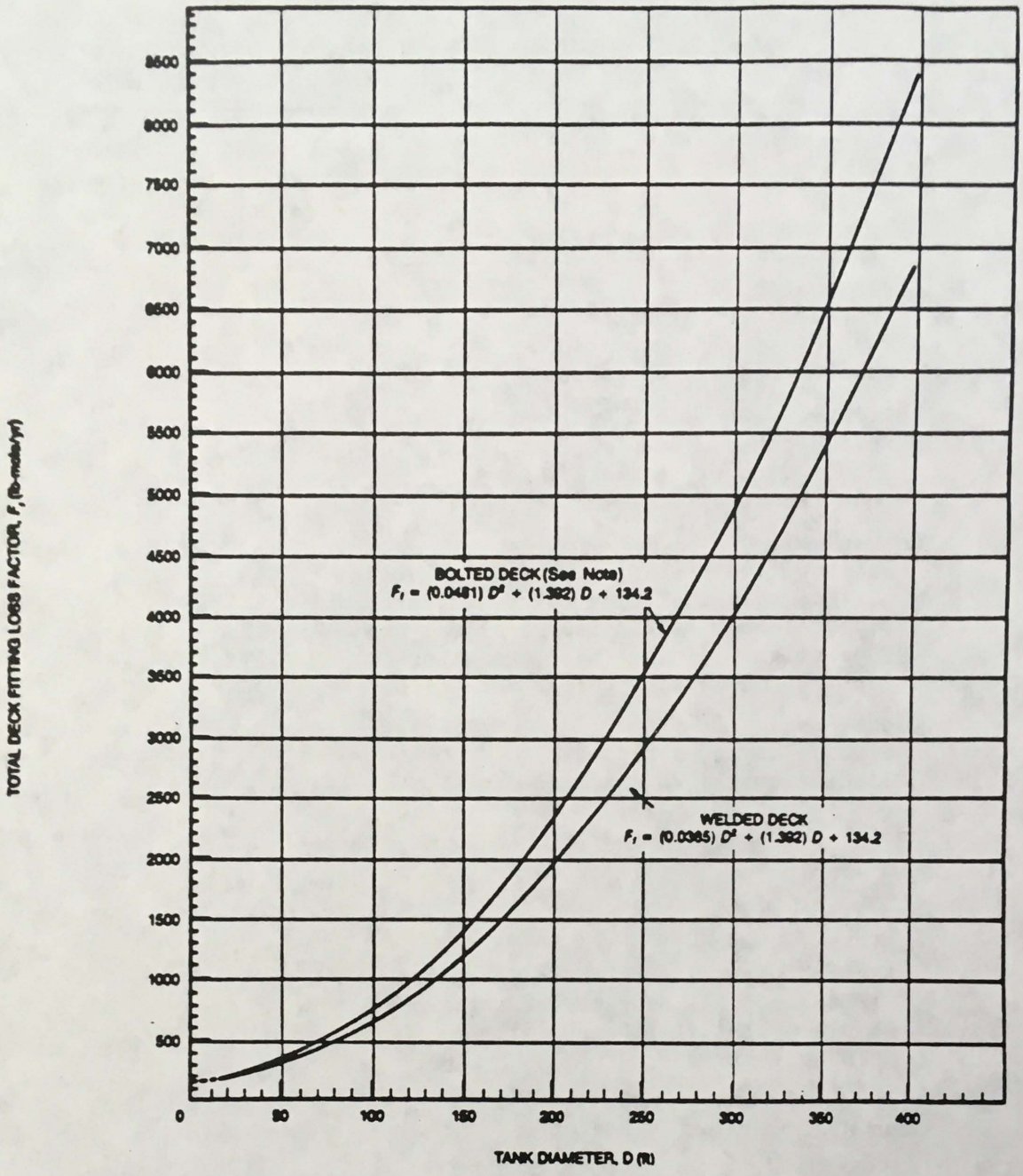
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TABLE 4.3-7. SUMMARY OF INTERNAL FLOATING DECK FITTING LOSS FACTORS (K_F) AND TYPICAL NUMBER OF FITTINGS (N_F)[a]

Deck fitting type	Deck fitting loss factor, K_F (lb-mole/yr)	Typical number of fittings, N_F
Access hatch		1
Bolted cover, gasketed	1.6	
Unbolted cover, gasketed	11[b]	
Unbolted cover, ungasketed	25[b]	
Automatic gauge float well		1
Bolted cover, gasketed	5.1	
Unbolted cover, gasketed	15[b]	
Unbolted cover, ungasketed	28[b]	
Column well		(see Table 4.3-6)
Builtup column-sliding cover, gasketed	33[b]	
Builtup column-sliding cover, ungasketed	47[b]	
Pipe column-flexible fabric sleeve seal	10	
Pipe column-sliding cover, gasketed	19	
Pipe column-sliding cover, ungasketed	32	
Ladder well		1
Sliding cover, gasketed	56[b]	
Sliding cover, ungasketed	76[b]	
Roof leg or hanger well		$(5 + \frac{D}{10} + \frac{D^2}{600})$[c]
Adjustable	7.9[b]	
Fixed	0	
Sample pipe or well		1
Slotted pipe-sliding cover, gasketed	44	
Slotted pipe-sliding cover, ungasketed	57[b]	
Sample well-slit fabric seal, 10% open area	12[b]	
Stub drain, 1 inch diameter[d]	1.2	$(\frac{D^2}{125})$[c]
Vacuum breaker		1
Weighted mechanical actuation, gasketed	0.7[b]	
Weighted mechanical actuation, ungasketed	0.9	

[a] Reference 1.
[b] If no specific information is available, this value can be assumed to represent the most common/typical deck fittings currently used.
[c] D = tank diameter (ft).
[d] Not used on welded contact internal floating decks.

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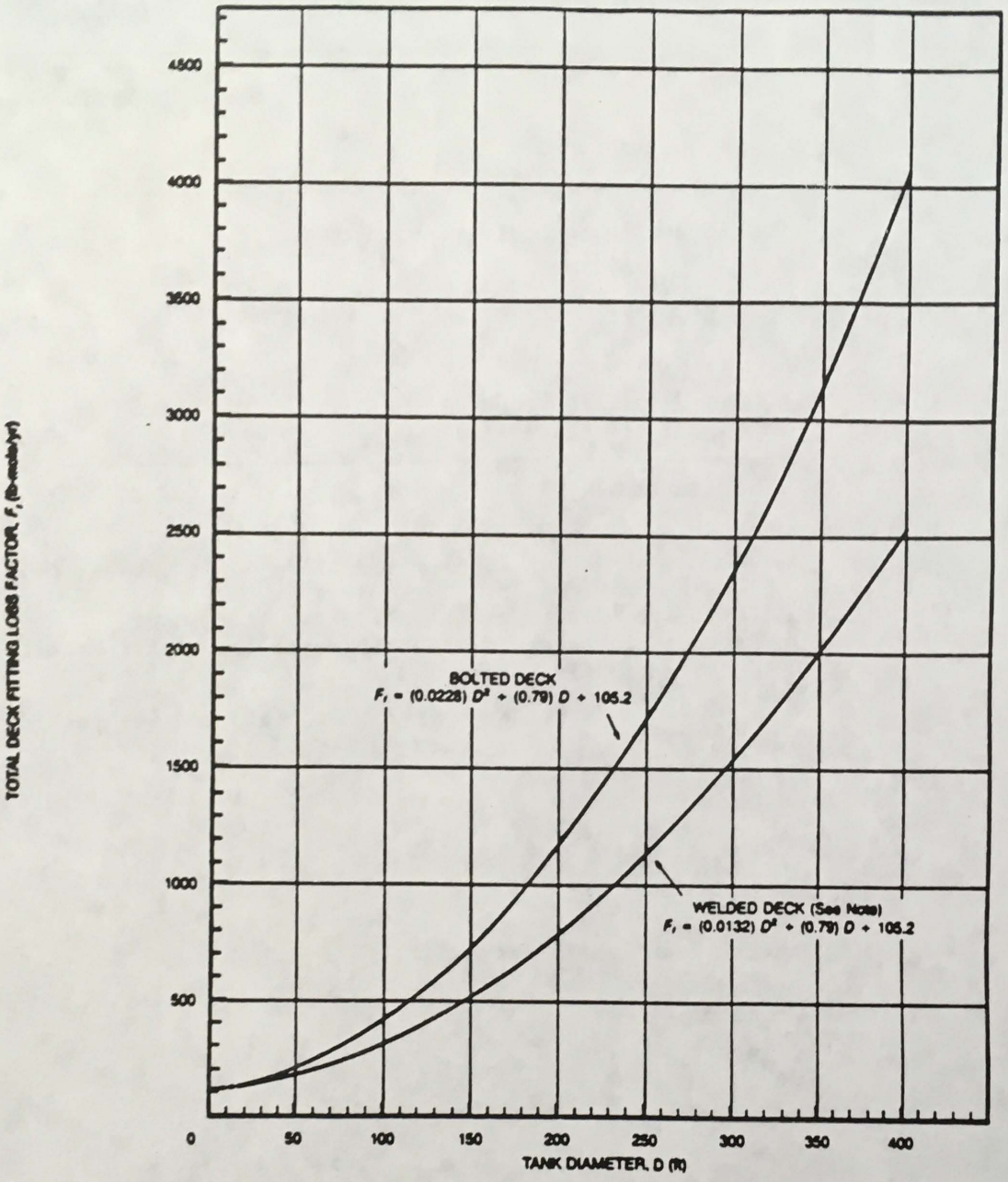


Basis: Fittings include: (1) access hatch, with ungasketed, unbolted cover; (2) built-up column wells, with ungasketed, sliding cover; (3) adjustable deck legs; (4) gauge float well, with ungasketed, unbolted cover; (5) ladder well, with ungasketed sliding cover; (6) sample well, with slit fabric seal (10 percent open area); (7) 1-inch diameter stub drains (only on bolted deck); and (8) vacuum breaker, with gasketed weighted mechanical actuation. This basis was derived from a survey of users and manufacturers. Other fittings may be typically used within particular companies or organizations to reflect standards and/or specifications of that group. This figure should not supersede information based on actual tank data.

Note: If no specific information is available, assume bolted decks are the most common/typical type currently in use in tanks with column-supported fixed roofs.

Figure 4.3-10. Approximated total deck fitting loss factors (F_f) for typical fittings in tanks with column supported fixed roofs and either a bolted deck or a welded deck.[6] This figure is to be used only when tank specific data on the number and kind of deck fittings are unavailable.

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BASIS: Fittings include: (1) access hatch, with ungasketed, unbolted cover; (2) adjustable deck legs; (3) gauge float well, with ungasketed, unbolted cover; (4) sample well, with slit fabric seal (10 percent open area); (5) 1-inch diameter stub drains (only on bolted deck); and (6) vacuum breaker, with gasketed weighted mechanical actuation. This basis was derived from a survey of users and manufacturers. Other fittings may be typically used within particular companies or organizations to reflect standards and/or specifications of that group. This figure should not supersede information based on actual tank data.

NOTES: If no specific information is available, assume welded decks are the most common/typical type currently in use in tanks with self-supporting fixed roofs.

Figure 4.3-11. Approximated total deck fitting loss factors (F_f) for typical deck fittings in tanks with self-supporting fixed roofs[f] and either a bolted deck or a welded deck.[6] This figure is to be used only when tank specific data on the number and kind of deck fittings are unavailable.

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TABLE 4.3-8. DECK SEAM LENGTH FACTORS (S_D) FOR TYPICAL DECK CONSTRUCTIONS FOR INTERNAL FLOATING ROOF TANKS[a]

Deck construction	Typical deck seam length factor, S_D (ft/ft^2)
Continuous sheet construction[b]	
5 ft wide	0.20[c]
6 ft wide	0.17
7 ft wide	0.14
Panel construction[d]	
5 x 7.5 ft rectangular	0.33
5 x 12 ft rectangular	0.28

[a]Reference 6. Deck seam loss applies to bolted decks only.

[b] $S_D = \frac{1}{W}$, where W = sheet width (ft)

[c]If no specific information is available, these factors can be assumed to represent the most common bolted decks currently in use.

[d] $S_D = \frac{(L+W)}{LW}$, where W = panel width (ft) and L = panel length (ft)

where:

S_D = deck seam length factor (ft/ft^2)

$$= \frac{L_{seam}}{A_{deck}}$$

L_{seam} = total length of deck seams (ft)

A_{deck} = area of deck (ft^2) = $\pi D^2/4$

D, P*, M_V, K_C = as defined for Equation 4

If the total length of the deck seam is not known, Table 4.3-8 can be used to determine S_D. Where tank specific data concerning width of deck sheets or size of deck panels are unavailable, a default value for S_D can be assigned. A value of 0.20 (ft/ft^2) can be assumed to represent the most common bolted decks currently in use.

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Estimating specific chemical emissions requires another step to determine the composition of vapor lost from the tanks. This vapor composition can be estimated in several ways, one of which is Raoult's Law. The Raoult's Law approach has been incorporated in the spreadsheets included in this Manual. Spreadsheet printouts corresponding to the three sample problems are presented in Section 080-002. The chemical compositions used for these examples have been added to illustrate speciation.

Chemical emissions are then calculated by multiplying the total VOC air emission quantity by the weight % vapor composition. Vapor composition is determined by its relationship to the liquid composition, assuming Raoult's Law. Raoult's Law requires that both the gas and liquid phases behave ideally, and is stated as follows:

$P_i = x_i P_i^v$ where: P_i is the specific chemical partial pressure of chemical species "i"
x_i is the liquid mole fraction of species "i"
P_i^v is the vapor pressure of pure chemical "i"

The sample problems in Sections 040-003, 050-003, and 060-003 only calculated the total VOC air emissions. For SARA 313 reporting, the chemical composition of the volatile air emissions must be included to estimate releases of specific chemicals. The details of the calculation procedure are provided in the following example. Consider a fixed roof tank in Section 040-002 storing crude MEK with the following composition:

Chemical	M.W.	Vapor Press., psi	Wt.%
MEK	72	1.4	80
SBE	130	0.23	3
TAA	180	0.68	5
SBA	74	0.25	12

The tank information is as follows:

Tank Height	40 ft
Tank Diameter	100 ft
Tank Color	White
Tank Volume	2350 k gal
Storage temperature	60.0 °F
Temperature swing	20 °F
Local pressure	14.7 psi
Rate of Throughput	1.5 M Bbl/yr
Turnovers per year	28.22
Tank factors:	
Paint Solar Absorbance, a	0.17
Vented Vapor Space Factor, K_s	0.4236
Product Factors, K_c	1.0
Vapor Space Expansion Factor, K_e	0.0595
Turnover Factor, K_n	1.0

To calculate VOC losses, we need to calculate liquid vapor pressure, P, and vapor molecular weight, M_v. This is shown below.

Chemical	M.W.	VP, psi	Wt%	Moles/ 100 lb	Partial Pressure	Vapor Weight	Vapor Wt%
MEK	72	1.4	80	1.111	1.175	69.12	94.05
SBE	130	.23	3	.023	.004	0.43	0.58
TAA	180	.68	5	.028	.014	2.10	2.85
SBA	74	.25	12	.162	.031	1.85	2.52
			100	1.324	1.224	73.50	100.00

The partial pressure (psi) is calculated from Raoult's Law as described on page 070-001. Assuming equilibrium, the vapor pressure of the liquid is equal to the sum of partial pressures of the individual components, 1.224 psi. Vapor molecular weight is obtained by multiplying each component's molecular weight by its vapor mole fraction (partial pressure/sum of partial pressures). Thus, the molecular weight of the VOC's in this example is 73.5. The final column normalizes this to 100 wt %.

Substituting these values into the formula for breathing losses:

$L_s = 365\ (165261)\ (0.0160)\ (0.0595)\ (0.4236)$

$L_s = 24{,}325$ lb/yr for a complete year.

Likewise, working losses are:

$L_w = 0.0010\ (73.50)\ (1.22)\ (1{,}500{,}000)\ (1.0)\ (1.0)$

$L_w = 134505$ lb/yr.

Total losses:

$L_T = L_s + L_w = 24{,}325 + 134{,}505 = 158{,}830$ lb/yr.

Of the chemicals listed, MEK and SBA are SARA chemicals, and their emissions would be reported as:

MEK emission = 158,830 x 0.9405 = 149,380 lb/yr.
SBA emission = 158,830 x 0.0252 = 4,003 lb/yr.

Three tank emissions spreadsheets are included on the diskette, one for fixed roof tanks, one for external floating roof tanks, and one for internal floating roof tanks. The programs are appropriately named FIXED.WK2, EXFLOAT.WK2, and INFLOAT.WK2, respectively. The programs are supplied with a "WK2" file extension to avoid accidental erasure during use. (Lotus® would automatically attach a "WK1" extension if a user inadvertently tried to save a modified file of the same name.) As each file is retrieved, an automatic "macro menu" is invoked from which the user can make the following choices:

INPUT	to begin inputting tank data
GOTO	to skip down to product composition section
TANKFORM	create columns containing formulas to input new tank data
COMPFORM	create columns containing formulas to input composition data
ADDCHEM	add chemical names and properties to list
PRINT	to print a designated portion of the worksheet
SAVE	to save the worksheet
REVISIONS	View/change notes on program revisions

This menu can be recalled at any time by typing "Alt M". To guard against inadvertent changes to the worksheet, the cells not requiring data entry were copy protected. In addition, titles were set to position the cursor at column "E", with columns "B through D" as titles. Column "A" contains the necessary formulas to perform the tankage calculations.

The spreadsheets included on the diskette provided at the end of this manual already contain the example problems discussed above. New data can either be input directly over this data, or blank columns can be created with the TANKFORM and COMPFORM commands. The best approach is to start with the ADDCHEM command and input names and physical properties for the chemicals needed. The COPY command can be used to move information already listed, but DO NOT use the MOVE command, as this will change cell references elsewhere in the program.

Once the chemicals are input, the next step should be to create columns to accept compositional information with the COMPFORM command. This macro works like the COPY command, prompting the user for a range to copy to. Use the arrow/tab keys in conjunction with the "." to set the number of columns to be created. (Be careful not to move the cursor up or down as this will cause the rows to be misaligned with the titles.)

The next step is to create columns for tank data using the TANKFORM command in the same way COMPFORM was used. Once the columns are created, data entry is relatively self-explanatory, but requires a working knowledge of the tables and figures included in AP-42 or API 2517. Note that the calculations will not be done automatically as data is entered because the programs have been set on manual recalculation. After all the information is input, calculation can be done by pressing the "F9" key.

The tank programs are similar, but differ in the number and type of tank factors needed to calculate evaporative losses. For example, the floating roof program has more space in the tank information section for indicat

the tank type, construction, and shell condition, as well as information on the number and type of seals used. This information is included for documentation purposes and has no impact on the calculations. Tank factors consistent with this information must be input separately based on the tables and figures from AP-42 or API 2517 (Sections 100-011, 100-002, and 100-003).

In all programs, tank volume is calculated based on the height and width specified, and should be based on the working height of the tank. Storage meteorological conditions are averages for the period under consideration and can be obtained from the local weather service. True vapor pressure and vapor molecular weight must be input. They can be obtained from sources such as Table 4.3-2 from AP-42, or can be calculated by the program based on the chemical composition input. The calculated values appear below the input cells. Throughput should be the projected annual amount, even if the tank is used for only part of the year. For example, 1000 gallons over three months should be input as 4000 gal/yr throughput for 25% of the year.

In the fixed tank program, the small tank adjustment and turnover factors are calculated by the program based on curve fits of the figures included in AP-42. For internal floating roof tanks, approximate values for the deck fitting loss factor are provided by the program based on curve fits of the figures included in AP-42. Also, in case specific information is not available, the typical number of supporting columns for a tank of a given diameter is provided. In all cases, even if a factor is calculated by the program, it will not be used by the correlation equations unless the desired number is input directly by the user. For example, the program automatically calculates the vapor pressure and the vapor molecular weight. However, you must still transfer those estimates to the highlighted input cells just above the computer-estimated values. Otherwise, the spreadsheet will not work.

Total VOC evaporative losses in lb/yr are calculated by the program. In cases where the tank was not used the entire year, this is the amount of air emissions during the period the tank was in service.

Information on the chemical content of the tank must be input if the specific chemical emissions are to be calculated. The program will calculate a vapor composition based on a Raoult's Law relationship with the liquid composition. If better means are available for estimating the vapor composition, this composition can be input directly into the "Vapor Wt%" row, overwriting the formula in that cell.

The use of sweep gas in a tank will increase emissions from that tank. A rough estimate would be three times the normal breathing loss without sweep gas. A better method is to actually measure the exhaust hydrocarbon concentration and flow rate (or inlet flow rate of sweep gas) to obtain the emissions rate.

Geodesic domes are self-supporting structures (no internal supports) which are used to lower tank emissions, sometimes as a retrofit over an existing external floating roof. A proposed method to calculate these emissions is to use the external floating roof method (API 2517) with a windspeed of 2 mile/hr. Contact ETS with questions concerning tanks using sweep gas or geodesic domes.

The fixed roof example problem (Section 040-003) is given in column 1 of the fixed roof tank spreadsheet printout (FIXED.WK2). Columns 2 and 3 are variations of the same problem that differ only in the tank's chemical composition. The top half of the first page of the table repeats the calculations of Section 040-002, with evaporative losses that are very close to the results obtained in the examples. The rest of the table is devoted to calculation of specific chemical emissions based on the three assumed tank compositions shown on the second page of the spreadsheet printout.

For example, the mogas composition approximates the true vapor pressure and vapor molecular weight of the problem statement. The spreadsheet calculates evaporative losses based on the vapor pressure and vapor molecular weight of the tank mixture. These numbers are calculated by the program, but must be directly input by the user in the cell above the calculated value. (This allows the user the flexibility to, for example, round to a whole number if desired. It also forces the user to review and accept the number calculated by the program.)

The results of the floating roof example problems (Sections 050-002 and 060-002) are shown in Section (080-002) which contains a printout of the floating roof emissions spreadsheets. For consistency, the floating roof examples incorporate the same three chemical compositions used in the fixed roof examples. As with the fixed roof problem three variations are presented for the other problems. The structure of the floating roof tanks spreadsheets is similar to the fixed roof version, although more factors need to be included to calculate the VOC air emissions. The specific chemical emissions are calculated in the manner described above.

The spreadsheets are structured so that each tank occupies a single column, making it at least theoretically possible to store 252 tanks (columns E through IV), in a single spreadsheet. Chemical compositions for given products are stored in a separate section of the spreadsheet, each with a unique "Product Number". Thus, it is possible for several tanks to have the same compositional information by inputting the same product number in the tankage calculations section. In this way, composition data for each product is input only once, which helps to avoid inconsistencies. The spreadsheet can also store 252 product compositions, as long as the cumulative number of chemicals does not exceed 15. Air emissions for all the tanks contained in each spreadsheet are summed under "Overall Total" in the chemical emissions section (col "D").

FIXED ROOF TANK EMISSIONS ESTIMATE (FIXED.WK2)
VERSION: 032293
DATE: 04/08/93
TYPE: "ALT M" FOR MENU
This program is based on the tankage evaporative loss calculation in API 2518, 2nd edition. Please consult this reference for tankage factors. SARA chemical emissions are determined by multiplying the total VOC emission by the Wt% vapor composition, as determined by Raoult's Law. The vapor pressures calculated by the spreadsheet are for 60 F. Because Raoult's Law is dependent on temperature, recalculation may be important for temperature deviations from 60 F.

TANK NUMBER	API 2518	EX 1	EX 2	EX 3
TANK COLOR	WHITE	WHITE	WHITE	WHITE
TANK HEIGHT, Hs (ft)	40	40	40	40
TANK DIAMETER, D (ft)	100	100	100	100
TANK VOLUME, V (k gal)	2350	2350	2350	2350
(k Bbl)	56.0	56.0	56.0	56.0
ROOF TYPE (CONE/DOME)	CONE	CONE	CONE	CONE
CONE ROOF PARAMETERS				
Tank Roof Slope, Sr (ft/ft) (default = 0.0625)	0.0625	0.0625	0.0625	0.0625
DOME ROOF PARAMETERS				
Dome Roof Radius, Rr (ft) (default = D)				
AVG AMBIENT TEMP, Taa (degF)	60.00	60.00	60.00	60.00
LIQUID BULK TEMP, Tb (degF)	60.02	60.02	60.02	60.02
LOCAL ATMOS PRESS, Pa (psia)	14.7	14.7	14.7	14.7
THROUGHPUT, Q (kgal/yr)	63000	63000	63000	63000
% OF YEAR USED	100	100	100	100
PAINT SOLAR ABSORPTANCE, a	0.17	0.17	0.17	0.17
SOLAR INSOLATION, I (BTU/ft2 day)	1200	1200	1200	1200
PRODUCT STORED	CRUDE	mogas	crude MEK	BTX
PRODUCT NUMBER		1	2	3
VAPOR MW, Mv (INPUT)	50.00	65.71	73.50	87.62
(CALC'D)		65.71	73.50	87.62
IS TANK WELDED (Y/N)	Y	Y	Y	Y
IF TANK IS WELDED ENTER:				
Brether Vent Press, Pbp (psig)	0.03	0.03	0.03	0.03
Breather Vent Vacuum, Pbv (psig) (default = +/-0.03)	-0.03	-0.03	-0.03	-0.03
ADDITIONAL DATA_____	_____	_____	_____	_____
FOR FIXED ROOF TANKS ONLY				
DIURNAL TEMP SWING, dTv (degF)	20	20	20	20
LIQUID HEIGHT, Hl (ft)	20	20	20	20
_____	_____	_____	_____	_____
MAXIMUM LIQUID HEIGHT, Hlx (ft)	38	38	38	38
ROOF OUTAGE, Hro (ft)	1.04	1.04	1.04	1.04
VAPOR SPACE OUTAGE, Hvo (ft)	21.04	21.04	21.04	21.04
AVG LIQUID SURFACE TEMP, Tla (degF)	61.62	61.62	61.62	61.62
VAPOR TEMP RANGE, dTv (degF)	20.11	20.11	20.11	20.11
MAX LIQUID SURFACE TEMP, Tlx (degF)	66.65	66.65	66.65	66.65
MIN LIQUID SURFACE TEMP, Tln (degF)	56.59	56.59	56.59	56.59
STOCK TURNOVER RATE, N	28.22	28.22	28.22	28.22
TVP @ MAX LIQ SURF TEMP, Pvx (psia)	0.96	5.65	1.43	0.34
TVP @ AVG LIQ SURF TEMP, Pva (psia)	0.85	5.38	1.22	0.32
Calculated Via Speciation (psia)		5.38	1.22	0.32
TVP @ MIN LIQ SURF TEMP, Pvn (psia)	0.75	4.90	1.09	0.26
TIME EVALUATED	ANNUAL	ANNUAL	ANNUAL	ANNUAL
STANDING STORAGE LOSS				
Tank Vapor Space Volume, Vv (ft3)	165261	165261	165261	165261
Stock Vapor Density, Wv (lb/ft3)	0.0076	0.0632	0.0160	0.0050
Vapor Space Expansion Factor, Ke	0.0489	0.1126	0.0594	0.0400
Vented Vapor Saturation Factor, Ks	0.5133	0.1429	0.4236	0.7370
STANDING STORAGE LOSS, Ls (lb/yr)	11497	61343	24319	8910

TABLE II-4 (Cont'd)

WORKING LOSS				
Working Loss Turnover Factor, Kn	1.00	1.00	1.00	1.00
Working Loss Product Factor, Kp	0.75	1.00	1.00	1.00
WORKING LOSS, Lw (lb/yr)	47818	530280	134505	42058
TOTAL VOC EMISSION FROM TANK (lb/yr)	59315	591623	158824	50967

VAPOR COMPOSITION, WT%

BENZENE	0.72	0.00	36.80
TOLUENE	1.01	0.00	52.01
XYLENE	0.22	0.00	11.20
NAPHTHA	20.43	0.00	0.00
BUTANES	77.62	0.00	0.00
MEK	0.00	94.05	0.00
SBE	0.00	0.58	0.00
TAA	0.00	2.85	0.00
SBA	0.00	2.52	0.00
10.00	0.00	0.00	0.00
11.00	0.00	0.00	0.00
12.00	0.00	0.00	0.00
13.00	0.00	0.00	0.00
14.00	0.00	0.00	0.00
15.00	0.00	0.00	0.00

CHEMICAL EMISSIONS, LB/YR

	OVERALL TOTAL	API 2518	EX 1	EX 2	EX 3
BENZENE	22997		4243	0	18754
TOLUENE	32502		5996	0	26506
XYLENE	6999		1291	0	5708
NAPHTHA	120863		120863	0	0
BUTANES	459230		459230	0	0
MEK	149368		0	149368	0
SBE	920		0	920	0
TAA	4534		0	4534	0
SBA	4001		0	4001	0
10	0		0	0	0
11	0		0	0	0
12	0		0	0	0
13	0		0	0	0
14	0		0	0	0
15	0		0	0	0

CHEMICAL COMPOSITIONS, WT%

PRODUCT NUMBER	1	2	3
PRODUCT STORED	mogas	crude MEK	BTX
BENZENE	2.00		2.00
TOLUENE	10.00		10.00
XYLENE	10.00		10.00
NAPHTHA	69.56		
BUTANES	8.44		
MEK		80.00	
SBE		3.00	
TAA		5.00	
SBA		12.00	
10.00			
11.00			
12.00			
13.00			
14.00			
15.00			
	100	100	22

TABLE II-4 (Cont'd)

WORKING LOSS				
Working Loss Turnover Factor, Kn	1.00	1.00	1.00	1.00
Working Loss Product Factor, Kp	0.75	1.00	1.00	1.00
WORKING LOSS, Lw (lb/yr)	47818	530280	134505	42058
TOTAL VOC EMISSION FROM TANK (lb/yr)	59315	591623	158824	50967

VAPOR COMPOSITION, WT%

BENZENE	0.72	0.00	36.80
TOLUENE	1.01	0.00	52.01
XYLENE	0.22	0.00	11.20
NAPHTHA	20.43	0.00	0.00
BUTANES	77.62	0.00	0.00
MEK	0.00	94.05	0.00
SBE	0.00	0.58	0.00
TAA	0.00	2.85	0.00
SBA	0.00	2.52	0.00
10.00	0.00	0.00	0.00
11.00	0.00	0.00	0.00
12.00	0.00	0.00	0.00
13.00	0.00	0.00	0.00
14.00	0.00	0.00	0.00
15.00	0.00	0.00	0.00

CHEMICAL EMISSIONS, LB/YR

	OVERALL TOTAL	API 2518	EX 1	EX 2	EX 3
BENZENE	22997		4243	0	18754
TOLUENE	32502		5996	0	26506
XYLENE	6999		1291	0	5708
NAPHTHA	120863		120863	0	0
BUTANES	459230		459230	0	0
MEK	149368		0	149368	0
SBE	920		0	920	0
TAA	4534		0	4534	0
SBA	4001		0	4001	0
10	0		0	0	0
11	0		0	0	0
12	0		0	0	0
13	0		0	0	0
14	0		0	0	0
15	0		0	0	0

CHEMICAL COMPOSITIONS, WT%

PRODUCT NUMBER	1	2	3
PRODUCT STORED	mogas	crude MEK	BTX
BENZENE	2.00		2.00
TOLUENE	10.00		10.00
XYLENE	10.00		10.00
NAPHTHA	69.56		
BUTANES	8.44		
MEK		80.00	
SBE		3.00	
TAA		5.00	
SBA		12.00	
10.00			
11.00			
12.00			
13.00			
14.00			
15.00			
	100	100	22

TABLE II-5 - EXTERNAL FLOATING ROOF SPREADSHEET

EXTERNAL FLOATING ROOF TANK EMISSIONS ESTIMATE (EXFLOAT.WK2)
VERSION: 113090
DATE: 11/30/90
TYPE: "ALT M" FOR MENU
This program is based on the tankage evaporative loss calculation in API Publication 2517, Third Edition, February 1989. Please consult this reference for tankage factors. SARA chemical emissions are determined by multiplying the total VOC emission by the Wt% vapor composition, as determined by Raoult's Law.

TANK NUMBER	Prob 2.4		
TANK: WELDED OR RIVETED	welded	welded	welded
SHELL CONDITION	light	light	light
PRIMARY SEAL:	metallic	metallic	metallic
SECONDARY:	none	none	none
TANK COLOR	aluminum	aluminum	aluminum
TANK DIAMETER, D (ft)	100	100	100
LOCAL ATMOS PRESS.(psia)	14.7	14.7	14.7
THROUGHPUT, Q (k gal/yr)	63000	63000	63000
WIND SPEED, V (mi/hr)	10	10	10
% OF YEAR USED	100	100	100
PRODUCT STORED	mogas	BTX	crude MEK
PRODUCT NUMBER	1	3	2
LIQUID DENSITY, (lb/gal)	6.10	6.10	6.10
VAPOR MW, Mv (INPUT)	64.00	88.04	73.50
(CALC'D)	66.00	88.04	73.50
VAPOR PRESS, psia (INPUT)	5.40	0.32	1.22
(CALC'D)	5.40	0.32	1.22
VAP PRESS FUNCTION, P*	0.114	0.006	0.022
TANK FACTORS			
SEAL FACTOR, Kr	1.20	1.20	1.20
WIND SPEED EXPONENT, n	1.50	1.50	1.50
PRODUCT FACTOR, Kc	1	1	1
SHELL CLINGAGE, C	0.0015	0.0015	0.0015
DECK FITTING LOSS, Ff	782	782	782
APPROX: PONTOON FLT ROOF	785	785	785
DOUBLE-DECK FLT ROOF	965	965	965
EVAPORATIVE LOSSES	lb/yr	lb/yr	lb/yr
RIM SEAL LOSS, LR	27677	1838	6040
DECK FITTING LOSS, LF	5704	379	1245
WITHDRAWAL LOSS, LW	129	129	129
TOTAL LOSS (VOC)	33510	2346	7415
VAPOR COMPOSITION, WT%			
BENZENE	0.70	36.14	0.00
TOLUENE	0.97	49.84	0.00
XYLENE	0.27	14.02	0.00
NAPHTHA	21.13	0.00	0.00
BUTANES	76.92	0.00	0.00
MEK	0.00	0.00	94.05
SBE	0.00	0.00	0.58
TAA	0.00	0.00	2.85
SBA	0.00	0.00	2.52
10	0.00	0.00	0.00
11	0.00	0.00	0.00
12	0.00	0.00	0.00
13	0.00	0.00	0.00
14	0.00	0.00	0.00
15	0.00	0.00	0.00

TABLE II-5 (Cont'd)

CHEMICAL EMISSIONS, LB/YR INDIVIDUAL TANKS:

	OVERALL TOTAL	Prob 2.4	0	0
BENZENE	1084	236	848	0
TOLUENE	1495	326	1170	0
XYLENE	421	92	329	0
NAPHTHA	7081	7081	0	0
BUTANES	25775	25775	0	0
MEK	6973	0	0	6973
SBE	43	0	0	43
TAA	212	0	0	212
SBA	187	0	0	187
10	0	0	0	0
11	0	0	0	0
12	0	0	0	0
13	0	0	0	0
14	0	0	0	0
15	0	0	0	0

CHEMICAL COMPOSITIONS, WT%

PRODUCT NUMBER	1	2	3
PRODUCT STORED	mogas	crude MEK	BTX
BENZENE	2		2
TOLUENE	10		10
XYLENE	10		10
NAPHTHA	69.56		
BUTANES	8.44		
MEK		80	
SBE		3	
TAA		5	
SBA		12	
10			
11			
12			
13			
14			
15			
	100	100	22

TABLE II-6 - INTERNAL FLOATING ROOF SPREADSHEET

INTERNAL FLOATING ROOF TANK EMISSIONS ESTIMATE (INFLOAT.WK2)
VERSION: 113090
DATE: 11/30/90
TYPE: "ALT M" FOR MENU
This program is based on the tankage evaporative loss calculation in AP-42, 4th edition. Please consult this reference for tankage factors.
SARA chemical emissions are determined by multiplying the total VOC emission by the Wt% vapor composition, as determined by Raoult's Law.

TANK NUMBER	Prob 1.3.2		
TANK: WELDED OR RIVETED	welded	welded	welded
SHELL CONDITION	light	light	light
PRIMARY SEAL:	vapor	vapor	vapor
SECONDARY:	none	none	none
TANK COLOR	aluminum	aluminum	aluminum
TANK DIAMETER, D (ft)	100	100	100
LOCAL ATMOS PRESS.(psia)	14.7	14.7	14.7
THROUGHPUT, Q (k gal/yr)	63000	63000	63000
% OF YEAR USED	100	100	100
PRODUCT STORED	mogas	BTX	crude MEK
PRODUCT NUMBER	1	3	2
LIQUID DENSITY, (lb/gal)	6.10	6.10	6.10
VAPOR MW, Mv (INPUT)	64.00	88.04	73.50
(CALC'D)	66.00	88.04	73.50
VAPOR PRESS, psia (INPUT)	5.40	0.32	1.22
(CALC'D)	5.40	0.32	1.22
VAP PRESS FUNCTION, P*	0.114	0.006	0.022
TANK FACTORS			
SEAL FACTOR, Ks	6.70	6.70	6.70
PRODUCT FACTOR, Kc	1	1	1
SHELL CLINGAGE, C	0.0015	0.0015	0.0015
DECK FITTING LOSS, Ff	773	773	773
APPROX VALUE: WELDED	658	658	658
BOLTED	754	754	754
DECK SEAM LOSS, Kd	0.34	0.34	0.34
DECK SEAM LENGTH, Sd	0.2	0.2	0.2
SUPPORTING COLUMNS, Nc	6	6	6
TYPICAL NUMBER, Nc	6	6	6
EFFECTIVE D, Fc (ft)	1.1	1.1	1.1
EVAPORATIVE LOSSES	lb/yr	lb/yr	lb/yr
RIM SEAL LOSS, LR	4887	325	1066
DECK FITTING LOSS, LF	5638	374	1230
DECK SEAM LOSS, LD	4960	329	1082
WITHDRAWAL LOSS, LW	138	138	138
TOTAL LOSS (VOC)	15622	1166	3517
VAPOR COMPOSITION, WT%			
BENZENE	0.70	36.14	0.00
TOLUENE	0.97	49.84	0.00
XYLENE	0.27	14.02	0.00
NAPHTHA	21.13	0.00	0.00
BUTANES	76.92	0.00	0.00
MEK	0.00	0.00	94.05
SBE	0.00	0.00	0.58
TAA	0.00	0.00	2.85
SBA	0.00	0.00	2.52
10	0.00	0.00	0.00
11	0.00	0.00	0.00
12	0.00	0.00	0.00
13	0.00	0.00	0.00
14	0.00	0.00	0.00
15	0.00	0.00	0.00

TABLE II-6 (cont'd)

CHEMICAL EMISSIONS, LB/YR	OVERALL TOTAL	INDIVIDUAL TANKS: Prob 1.3.2	0	0
BENZENE	532	110	421	0
TOLUENE	733	152	581	0
XYLENE	206	43	164	0
NAPHTHA	3301	3301	0	0
BUTANES	12016	12016	0	0
MEK	3308	0	0	3308
SBE	20	0	0	20
TAA	100	0	0	100
SBA	89	0	0	89
10	0	0	0	0
11	0	0	0	0
12	0	0	0	0
13	0	0	0	0
14	0	0	0	0
15	0	0	0	0

CHEMICAL COMPOSITIONS, WT% PRODUCT NUMBER	1	2	3
PRODUCT STORED	mogas	crude MEK	BTX
BENZENE	2		2
TOLUENE	10		10
XYLENE	10		10
NAPHTHA	69.56		
BUTANES	8.44		
MEK		80	
SBE		3	
TAA		5	
SBA		12	
10			
11			
12			
13			
14			
15			
	100	100	22

SECONDARY
EMISSIONS

According to the Clean Air Act, "Secondary emissions are emissions which occur as a result of construction or operation of a major stationary source but do not come from the major stationary source itself." Under this definition, secondary emissions would include air emissions resulting from the handling or disposal of wastes in another medium (water or land). Therefore, specific examples of secondary emission sources are sewers, flumes, grit chambers, sumps, equalization basins, pH adjustment stations, nutrient addition stations, clarifiers, oil-water separators, surface impoundments or open tanks, drum or container storage facilities, waste transfer lines, ditches, landfills, land treatment sites, and biological treatment systems. Because of the potential for hydrocarbon leakage in heat exchangers, cooling towers may also be a source of secondary emissions.

The determination of secondary emissions is difficult because the sources may involve large areas of water exposed to the atmosphere which contain very low concentrations of dissolved and/or suspended organic compounds. A major atmospheric emission may correspond to a small (and largely unmeasurable) loss of total organic carbon (TOC) from the wastewater. Direct measurement of the source is often physically difficult, because of location and system configuration. The published correlations and emission factors available to estimate secondary emissions are relatively inaccurate or non-existent. US EPA developed models are available to predict emissions for some units. These models are thought to be accurate to an order of magnitude, however, not all have been validated by experimental data.

DRAFT

ESTIMATING ALTERNATIVES FOR SECONDARY EMISSIONS

	EMISSIONS ESTIMATION METHODS FOR WASTE WATER TREATMENT SYSTEM UNITS		
UNIT/SOURCE	MODELS	EMISSION FACTORS	OTHER
SEWER/DRAINS		AP-42 factor	Measurement
API SEPARATORS	Chemdat7: Oil film impoundment & Non-aerated impoundment	(i) AP-42 factor (ii) EPA Reference "a" factor	(i) Litchfield equation for oil layer emissions (ii) Measurement
DAF	Chemdat7: Aerated Impoundment	EPA Reference "a" factor	Measurement
IAF	Chemdat&: Aerated Impoundment	EPA Reference "a" factor	Measurement
BIOX	Chemdat7: Aerated Impoundment		Measurement
EQUALIZATION TANKS/BASINS & LAGOONS	Chemdat7: Non-Aerated Impoundment		Measurement
COOLING TOWER		AP-42 factor	Measurement

Reference (a): VOC emissions from Petroleum Refinery Wastewater Systems Information for Proposed Standards, EPA-450/3-85-001A, February, 1985.

SECTION	SUBJECT	DATE ISSUED
010-000	Introduction	March 93
020-000	Table of Contents	March 93
040-	Secondary Emission Sources	March 93
-001	API Separators	March 93
-002	Air Floatation Units	March 93
-003	Biological Oxidation Systems	March 93
-004	Cooling Towers	March 93
-005	Other Sources	March 93
050-	Emission Estimating Tools	March 93
-001	AP-42 Emission Factors	March 93
-002	EPA CHEMDAT 7 Model	March 93
-003	LITCHFIELD Method (Oil/Water Separators)	March 93
-004	Other Emission Models	March 93
060-	Example Calculations (CHEMDAT 7)	March 93
-001	Equalization Basin	March 93
-002	Uncovered Tank	March 93

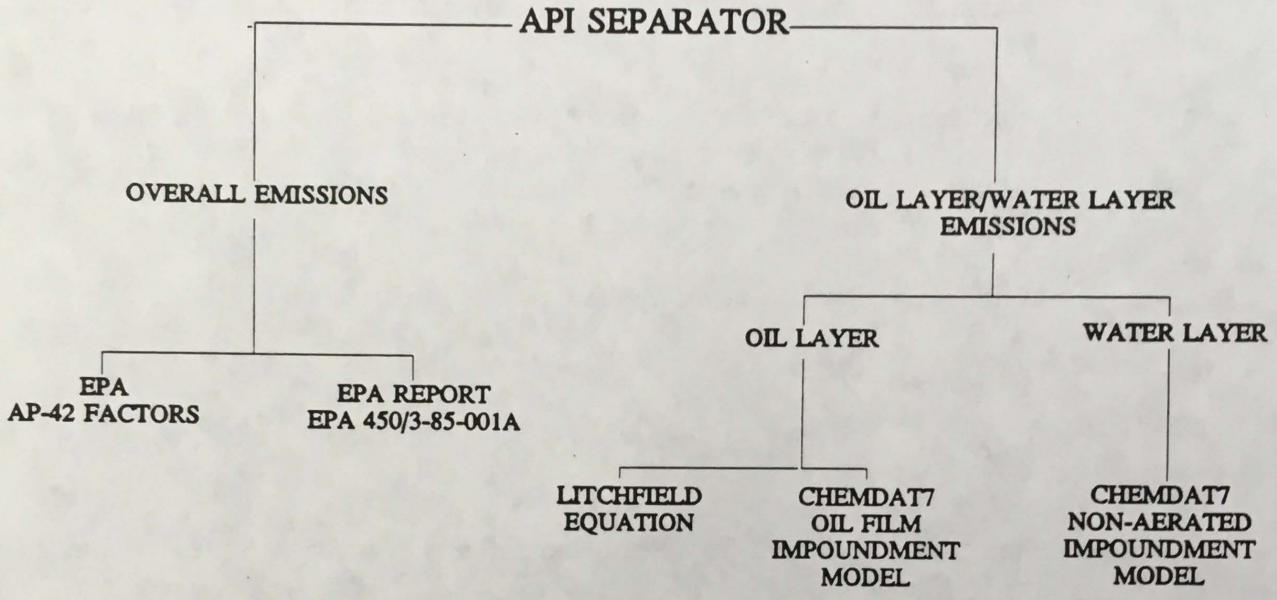
Within a wastewater treatment system, the largest source of secondary emissions is most often the primary oil-water-solids separator (API separator). It usually consists of an open channel in which wastewater flows slowly (less than 1 m/minute) allowing oil to float to the top and solids to sink to the bottom.

Several options are available to estimate the emissions from API separators. These options, ranging from an estimate of the overall API separator emission to determination of the individual component emissions from both the oil and water layers, are listed in Figure SE.1. The Litchfield Method for Oil-Water separators is recommended for API separator oil layer emissions calculations and is described in the "Emission Estimation" section. AP-42 and EPA Reference "a" emission factors for covered and uncovered API separators are presented in Table SE.1. The use of these emission factors will typically produce overly conservative emission estimates.

Covering the API separator greatly reduces the emissions and corrections to the predicted emission rate must be made to reflect this control measure. A tightly sealed and gasketed fixed roof can achieve a 99% reduction in emissions. Floating roofs with primary and secondary seals achieve lower reductions (90%) since small gaps between the separator and cover remain. Fixed roofs which are not tightly sealed should also be credited for a 90% reduction.

Figure SE.1

Estimating Options for API Separator Emissions



The procedure to estimate the emission is:

Step 1 - Determine the flow rate of waste water to the API Separator gal/hr or l/hr.

Step 2 - Determine whether the API separator is covered or not, and the type of cover (tightly sealed, loose cover)

Step 3 - Select the appropriate emission factor from Table SE.1. Guidance is for an API separator which is not constantly covered with a thick layer of oil - use the EPA Reference "a" factors. If an oil layer is generally present and oil skimming is infrequent (weekly or less frequent) - the AP-42 factor is more appropriate.

Step 4 - Multiply the emission factor by the flow rate to obtain the emission.

EPA Reference (a): VOC emissions from Petroleum Refinery Wastewater Systems Information for Proposed Standards EPA-450/3-85-001A, 2/85.

Table SE.1
API Separator Emission Factors

UNITS	UNCONTROLLED	CONTROLLED
AP-42 1L FEED = 1L WASTEWATER		
KG/1000 L WASTEWATER	0.6	0.024[a]
KG/1000 L REFINERY FD	0.6	0.03[a]
(CONTROLLED = SIMPLE FIXED/FLOATING COVERS)		
EPA DOCUMENT*2 L FEED=1 L WASTEWATER		
KG/1000 L WASTEWATER	0.111[b]	0.017[c]
KG/1000 L REFINERY FD	0.056	0.008[c]
(CONTROLLED = SIMPLE FIXED/FLOATING COVERS)		
KG/1000 L WASTEWATER		0.0033[d]
KG/1000 L REFINERY FD		0.0017[d]
(CONTROLLED = FIXED/FLOATING COVER W/SEAL & CONTROL DEVICE)		

* VOC EMISSIONS FROM PETROLEUM REFINERY WASTEWATER SYSTEMS INFORMATION FOR PROPOSED STANDARDS, EPA-450/3-85-001A, 2/85

Notes:

(a) These numbers are as they appeared in the AP-42 publication and requires a tightly gasketed solid cover or floating cover with tight edge seals.

(b) This factor is derived from the 0.056 kg/1000 l refinery feed and assumes a 2l feed and 1l wastewater ratio.

(c) This factor is derived from the uncontrolled 0.056 kg/1000l refinery feed emission. It assumes a combined control efficient of 85%.

(d) This factor is derived from the uncontrolled 0.056 kg/1000l refinery feed emission. It assumes a combined control efficient of 97%.

In dissolved air flotation (DAF) units, air dissolved under pressure bubbles from solution as the pressure is released, attaches to suspended solids and oil, and floats them to the surface. Fugitive hydrocarbons can be emitted with the flotation air itself, with any excess air pumped into the saturation drum, and by direct evaporation from the open DAF unit. AP-42 emission factors are not provided. CHEMDAT7's aeration model can be used as a screening tool to estimate emissions by supplying a subsurface air flow rate and setting the biomass to 0.0 mg/l.

In induced air flotation (IAF) units, air is introduced into the water by agitation (approximately 0.4 m^3 per m^3 feed) rather than by dissolution. AP-42 emission factors are not provided. It is certain, however, that the agitation greatly increases emissions over those from DAF units. CHEMDAT7's aerated treatment unit model can be used as a screening tool to model this case with the biomass set to 0.0 mg/l.

In dissolved air flotation (DAF) units, air dissolved in the wastewater under pressure bubbles from solution as the pressure is released and attaches to suspended solids and oil, floating them to the surface where they can be recovered. Hydrocarbons can be emitted with the flotation air itself, when excess air is pumped into the saturation drum, and by direct evaporation from the open DAF unit.

In induced air flotation (IAF) units, air is introduced into the water by agitation (approximately 0.4 m^3 air, per m^3 wastewater) rather than by dissolution. It is likely, however, that the agitation makes the emissions from IAF units greater than those from DAF units.

The emissions from both of these units can be determined either by direct measurement, by using Chemdat7, or by using published emission factors. The emission factors for DAF units and IAF units are presented in Table SE.2. The procedure for use of the Chemdat7 method is discussed beginning on page 3 of this subsection.

The procedure to estimate the emission is:

Step 1 - Determine the flowrate of wastewater to the unit in m^3/hr.

Step 2 - Determine the appropriate factor, based upon unit type and control present from Table SE.2.

Step 3 - Multiply the emission factor by the flowrate to obtain the emission rate in kg/hour.

Note: EPA Reference "a". VOC Emissions from Petroleum Refinery Wastewater Systems Information for Proposed Standards, EPA-450/3-85-001A, 2/85.

The following is a list of data needed to estimate the hydrocarbon emissions from DAF units using CHEMDAT7 and possible sources of the information.

Data	Units[b]	Where
Waste water flow rate	m^3/s	2
Water composition[a]	mg/l	5
Exposed surface area of DAF	m^2	1
Stream temperature	°C	3,6
Windspeed	m/s	4
Depth of DAF	m	1
Submerged air flow	m^3/s	3
Active Biomass Concentration	g/l	3,5
Influent Biomass Solids Concentration	g/l	3,5
Total Biorate (Biodegradation rate)	mg/g bio-hr	7

Sources of Information

1) Facility construction drawings
2) Facility water discharge reports
3) Process design data
4) Meteorological station
5) Laboratory wastewater analysis
6) Measurements
7) Chemdat7 manual or literature

Note: (a) Individual hydrocarbon component concentrations are required.
(b) Chemdat7 model requires input in metric units.

The following is a list of data needed to estimate the hydrocarbon emissions from IAF units using the CHEMDAT7 model and possible sources of the information.

Data	Units[b]	Where
Windspeed	m/s	4
Depth	m	1
Exposed surface area	m^2	1
Wastewater flowrate	m^3/s	2
Active biomass concentration	g/l	5,3
Influent biomass solids concentration	mg/l	5,3
Water composition[a]	mg/l	5
Total Biorate (Biodegration rate)	mg/g bio-hr	7
Submerged air flow	m^3/s	3
No. of Impellers		1
Oxygen transfer rate	lb O_2/hour-hp	3
Power of impeller meter	hp	3
Power efficiency		3
Temperature	°C	3,6
Impeller diameter	cm	1,3
Impeller speed	radian/s	1,3

Sources of Information
1) Facility construction drawings
2) Facility water discharge reports
3) Process design data
4) Meteorological station
5) Laboratory wastewater analysis
6) Measurements
7) Chemdat7 manual or literature

Note: (a) Individual hydrocarbon component concentrations are required.
(b) Chemdat7 model requires input in metric units.

The procedure to estimate the emission is:

Step 1 - Select CHEMDAT7's aerated wastewater treatment unit model

Step 2 - Gather the data identified in 040-002, page 3 or 4.

Step 3 - Enter required parameters into Chemdat7 program[a].

Note: (a) If active biomass and influent biomass solids concentrations are unknown use 0.0 mg/l as a conservative default value.

Biological oxidation systems include aerated lagoons, activated sludge (BIOX) units, trickling filters, and rotating biological discs. Measurements have shown that the emission rate of hydrocarbons is in the range of an order of magnitude greater than the water evaporation rate. The hydrocarbon loss is directly proportional to the wastewater flow rate and the hydrocarbon concentration.

The emissions from a Biox unit can be determined by direct measurement, or by using an EPA developed air prediction model in Chemdat7. No published emission factors for Biox units are available. Chemdat7 utilizes a Monod-type kinetic model to estimate biodegradation, giving first-order biodegradation behavior at low concentration and zero order behavior at high concentration. The aerated wastewater treatment model can be used as a screening tool for BIOX basin emission predictions.

The following is a list of data needed to estimate the hydrocarbon emissions from a biological oxidation system (BIOX) using the CHEMDAT7 model and possible sources of the information.

Data	Units[b]	Where
Windspeed	m/s	4
Depth	m	1
Exposed surface area	m^2	1
Wastewater flowrate	m^3/s	2
Active biomass concentration	g/l	5,3
Influent biomass solids concentration	mg/l	5,3
Water composition[a]	mg/l	5
Total Biorate (Biodegration rate)	mg/g bio-hr	7
Submerged air flow	m^3/s	3
No. of Impellers		1
Oxygen transfer rate	lb O_2/hour-hp	3
Power of impeller meter	hp	3
Power efficiency		3
Temperature	°C	3,6
Impeller diameter	cm	1,3
Impeller speed	radian/s	1,3

Sources of Information
1) Facility construction drawings
2) Facility water discharge reports
3) Process design data
4) Meteorological station
5) Laboratory wastewater analysis
6) Measurements
7) Chemdat7 manual or literature

Note: (a) Individual hydrocarbon component concentrations are required.
(b) Chemdat7 model requires input in metric units.

The procedure to estimate the emission is:

Step 1 - Select CHEMDAT7's aerated wastewater treatment unit model

Step 2 - Gather the data identified in 040-003, page 2.

Step 3 - Enter required parameters into Chemdat7 program.

Emission Estimating Guide	Secondary Emissions 040-004
Section: Cooling Towers	**Subject:** Background

Because of potential hydrocarbon leakage in heat exchangers, cooling towers are potential sources of secondary emissions. The hydrocarbon emission rate from water circulated in cooling towers is a function of the hydrocarbon content of the water. The secondary emissions can be determined by direct measurement or using emission factors. The AP-42 emission factors are provided in Table SE.2.

The procedure to estimate the emission is:

Step 1 - Determine the flow rate of circulating water in the cooling towers (gpm)

Step 2 - Determine the appropriate factor from Table SE.2 depending on whether the hydrocarbon concentration in the return cooling water is monitored or not.

Step 3 - Multiply the flow rate (Step 1) by the emission factor (Step 2) to get the emission rate in lbs/minute.

Emission Estimating Guide	Secondary Emissions 040-005

Section:	Subject:
Process Drains and Other Sources	Background

An often neglected potential source of secondary emissions from a plant is the network of sewers, lift stations, manholes, sumps and junction boxes through which wastewater is collected and transported to the treatment facility. The magnitude of emissions from this source is dependent upon the equipment design. Those sources which have been designed to have little contact with air have lower emissions than those which have no "control".

The methods of determining these emissions are either direct measurement or the use of emission factors. AP-42 emission factors are available only for process drains and are presented in Table SE.2. No model to predict emissions from this source is available.

The procedure to estimate the emissions from process drains is:

Step 1 - Count the number of process drains.

Step 2 - Determine the appropriate factor from Table SE.2 depending on whether the drains have a liquid seal or not.

Step 3 - Multiply the number of drains (Step 1) by the emission factor (Step 2) to determine the hourly hydrocarbon emission rate.

Emission factors for the potential sources of secondary emissions which follow are taken from the two following U.S. EPA publications.

AP-42 Compilation of Air Pollutant Emission Factors Stationary Point and Area Sources, 4th Edition.

VOC Emissions from Petroleum Refinery Wastewater Systems Information for Proposed Standards, EPA-450/3-85-001A, 2/85.

TABLE SE.2
EMISSION FACTORS

The available emission factors for several secondary emission sources are summarized below:

Emission Source	Emission Factor Units	VOC Emission Factor	
		Uncontrolled	Controlled
Process drains	AP-42 lb/hr-source	0.07	0.035[a]
Cooling Towers	AP-42 lb/10^6 gallons of circulating water	6	0.7[b]
Oil/Water Separators	AP-42 lb/10^3 gallons of wastewater	5	0.2[c]
Oil/Water Separators	EPA kg reference "a" 1000 l refinery feed	0.056	0.008[(d)] 0.0017[e]
DAF Unit	EPA reference "a" kg/1000m^3 wastewater	4.01	
IAF Unit	EPA reference "a" kg/1000m^3 wastewater	4.01	0.79

a Sealed drains are allowed to take a 50% reduction in emissions over unsealed drains per US EPA wastewater NSPS.
b Use of this factor requires a low ppm hydrocarbon detector on the cooling water return.
c Use of this factor requires a tightly gasketed solid cover or floating cover with tight edge seals.
d Use of this factor requires a simple fixed/floating cover on the API separator.
e Use of this factor requires a fixed/floating cover water seal and vapor control device (97% efficient)

Reference (a) VOC Emissions from Petroleum Refinery Wastewater Systems Information for Proposed Standards, EPA-450/3-85-001A, 2/85.

EPA has developed a group of air emission models for Hazardous Waste Treatment, Storage, and Disposal Facilities, which are contained in a single large Lotus®123 spreadsheet called CHEMDAT7.WK1. This tool is included on a diskette at the back of this manual. Additional chemical data is stored in an extra worksheet, DATATWO.WK1. Both of these worksheets have a ".WK1" file extension, and, therefore, can be overwritten. It is strongly recommended that a working copy of these files be made and that the originals be stored in a safe location (as you would do for any other commercial software program) to preserve the original program.

The CHEMDAT7 models are now available in a more user friendly form in EPA's WATER7 and LAND7. At the present time, experience on the use of these new models is limited.

Some of the bases and assumptions upon which CHEMDAT7 was developed are:

Basis

- Volatilization and biodegradation are the only important volatile organic removal pathways.
- The concentration of an individual constituent in the water phase is known.

Assumptions

- Operating system is at steady state conditions.

Overall model strengths and weaknesses are summarized in Table SE.3. Not all of the CHEMDAT7 models have been validated, and ER&E currently recommends only one model, the non-aerated surface impoundment model, for emission estimating. The model can be used to estimate evaporative loss from quiescent surfaces such as equalization basins, separators, trenches and ditches. However, the model assumes fully mixed flow. Systems that are plug flow, or not largely backmixed, can be simulated by dividing them into several quiescent stages in series, and calculating emissions for each stage separately using CHEMDAT7.

The aerated surface impoundment model can be used as a screening tool to predict emissions from Air Floatation Units, BIOX basins, or other units with submerged or surface aeration.

There are other tools for aerated surface emissions estimating. However, these tools are more difficult to use and it is suggested that plants contact ER&E if more detailed analysis of aerated treated units is required. Section 050-004 describes one of these tools, Chemical Manufacturers Association, (CMA's) PAVE model.

Detailed documentation of the various models as well as a CHEMDAT7 users manual are available in a single document from EPA.[5] This document, "Hazardous Waste Treatment, Storage, and Disposal Facilities (TSDF) - Air Emission Models, EPA-450/3-87-026, November, 1989, Review Draft, should be obtained before attempting to use the CHEMDAT7 spreadsheet. Appendix A of the EPA document contains the user's guide.

Additional Basis and Model Assumptions

- Springer, et al (University of Arkansas) mathematical methods for estimating individual liquid-phase mass transfer coefficients are appropriate for most quiescent surfaces.
- MacKay and Yeun mathematical methods for estimating individual liquid-phase mass transfer coefficients are appropriate for other quiescent surfaces.
- Thibodeaux (liquid phase) and Reinhardt (gas phase) mathematical methods are accurate for surface aerated basins.
- Overall mass transfer coefficient is estimated from a two-phase resistance model.
- Open tanks are treated as small impoundments.
- Impoundment contents assumed to be well-mixed. (Bulk concentration is everywhere equal to the effluent concentration.)
- Submerged air flow chemical concentrations reach equilibrium with the liquid-phase chemical concentrations.
- The waste material of interest is aqueous waste with no separate organic phase.
- In the biodegradation model, the Monod kinetic model is applicable.

TABLE SE.3

EVALUATION OF USEPA CHEMDAT7 EMISSION ESTIMATING MODEL

Model Strengths	Model Weaknesses/Limitations
Model is a Lotus®123 spreadsheet. Model is relatively quick (typically less than 10-15 seconds run-time on IBM PC AT). Model includes built-in physical property database for 61 compounds. Data for over 700 compounds are included in model documentation.	Volatilization and biodegradation are considered the only important removal pathways. Thus, photo-decomposition, hydrolysis, oxidation/reduction, and adsorption are assumed negligible. In PACT (powdered activated carbon treatment) and high suspended solids (> 1000 ppm) systems, adsorption can be important. Hydrolysis could be important if organic acids are present. Model is only partially sensitive to temperature. Changing the input affects the mass transfer correlations, but does not change vapor pressure, diffusivities, or any other parameter which is a function of temperature. It is insensitive to site characteristics and predicts similar emissions rates for bro classes of chemicals. The liquid-phase mass transfer coefficient correlation is based on work performed at the University of Arkansas by Springer, et al on a laboratory ethyl ether/water system. His results are extrapolated to other compounds by the ratio of the compound's and ether's diffusivities in water to the 2/3 power. To our knowledge, the validity of this extrapolation has not been tested. Henry's Law constants are for pure compounds and do not consider the effect of chemical composition. Recent literature indicates that Henry's Law constants can vary as much as 35 percent in complex mixtures. (6) Not all the needed physical property data are provided. Diffusivity and biorate data are lacking for some compounds. Biorate data are for pure compounds. Biorate data may be site-specific due to the effect of other compounds and unit operations for the particular system of interest.

In the Background Information Document (BID) for proposed standards for petroleum refinery wastewater systems (7), EPA indicated that the Litchfield equation can be used to estimate the percent volume loss from oil-water separators under a set of conditions more representative of present day refineries and chemical plants.

The AP-42 emission factor (5 lb/1000 gallons wastewater) is based on a Los Angeles County study conducted in 1958. Since industry has been reducing the amount of oil lost to wastewater streams, an emission factor determined in 1958 is overly conservative (high). The BID indicates that both the American Petroleum Institute and the State of California have recently used the Litchfield Method for emission factor development work.

The Litchfield study (8) used a small hot water bath to simulate the operating conditions of an API separator. Tests were conducted by placing weighed pans of an actual API separator influent oil in the hot water bath. After 24 hours the pans were reweighed and the losses calculated. The results of this study related the percent volume loss of oil in a separator to the ambient temperature, influent wastewater temperature, and the 10 percent true boiling point of the influent oil. The 10 percent point is an indication of the oil's vapor pressure. The lower the 10 percent true boiling point, the higher the vapor pressure.

The relationship developed by Litchfield is as follows:

$$V = -6.6339 + 0.0319\,X - 0.0286\,Y + 0.2145\,Z$$

Where:

V = Percent volume loss after 24 hours
X = Ambient temperature (°F)
Y = 10% True boiling point (°F)
Z = Influent temperature (°F)

Based on EPA values for representative oil properties and refinery wastewater operating temperatures as listed in Table SE.4, a percent volume loss rate of 12.6 percent was calculated. Assuming an influent oil concentration of 880 mg/L, an uncontrolled emission factor of 924 lb/million gallons of wastewater is calculated. (This is considerably less than the AP-42 value of 5000 lb/million gallons).

The percent volume loss can be modified if the residence time of the oil phase is known to be different than twenty-four hours. First, calculate the percent volume loss from the Litchfield equation. Assuming plug flow through the separator, calculate the emissions constant as shown in the following formula.

$$K = -\frac{\ln(1-V)}{24}$$

K = Emissions constant (Hr^{-1})
V = Percent volume loss after 24 hours (Hr)

Then, calculate the true volume fraction emitted by:

$V_{ew} = 1\text{-}e^{-Kt}$

V_{ew} = Percent volume loss after oil residence time
K = Emissions constant (Hr^{-1})
t = Oil phase residence time (Hr)

Speciation of emissions can be performed using Raoult's Law.

Although many researchers have studied separator VOC emissions (e.g., Jones and Vilas and Shell Oil Company (7), the Litchfield Method is the most straightforward and most widely applicable. Also, EPA has judged the Litchfield Method the best available tool for estimating VOC emissions from oil-water separators. In summary, the Litchfield Method is recommended rather than the AP-42 emission factor.

TABLE SE.4

EPA REPRESENTATIVE OIL PROPERTIES AND WASTEWATER TEMPERATURES

Ambient Temperature	65°F
Influent Temperature	120°F
10% True Boiling Point	300°F
Influent Oil Concentration	1000 ppmV (880 mg/L)
Specific Gravity	0.88

The USEPA has distributed a second model known as Surface Impoundment Modeling System (SIMS). SIMS predicts emissions based on assumed chemical concentrations for a particular industry and the surface area of the modeled unit. SIMS predicts emissions based on an assumed industry average influent to the waste water treatment plant. Therefore, its accuracy for a particular unit will be poor. One could modify the chemical component list and influent concentrations to match recorded data. Since SIMS uses the same model correlations as CHEMDAT7, it will give the same results at 25°C (SIMS assumes 25°C).

The guidance document for SIMS is Surface Impoundment Modeling System (SIMS) User's Manual, EPA-450/4-89-013a, September 1989. It is <u>not</u> recommended for emissions estimation since CHEMDAT7 allows the temperature as an input and because its contains a more extensive library of chemical compounds than SIMS. Government agencies, however, may use SIMS in their activities.

The Chemical Manufacturer Association (CMA) has issued its secondary emissions model, Program to Assess Volatile Emissions (PAVE). PAVE incorporates three separate models: one for surface-aerated activated sludge units, one for subsurface air flow units, and one for spills. PAVE requires many more inputs than CHEMDAT7. Also, PAVE does not have a built-in database of component properties. Thus, a separate component database has to be constructed. Comparing PAVE's predicted emissions to experimental data, PAVE's prediction behavior is similar to CHEMDAT7's but predicts, on average, slightly lower emissions than CHEMDAT7.

The following examples indicate how CHEMDAT7 may be used to predict secondary emissions from two wastewater treatment facilities generally found at chemical plants.

Example Problem 1

Consider an equalization basin (no oil layer) with the following characteristics:

	English	Metric
Depth	5 ft	1.524 m
Surface Area	9000 ft^2	837 m^2
Flow	388 gpm	0.0245 m^3/s
Temperature	77 °F	25 °C
Windspeed	10 mph	4.47 m/s

Composition Data:

Methyl Ethyl Ketone (MEK)	17.4 mg/l
Methyl Isobutyl Ketone (MIBK)	16.1 mg/l
Acetone	1.0 mg/l

CHEMDAT7 can be used to calculate air emissions as follows:

- After loading the spreadsheet, select "SORT", "ALPHABET" and then "SORT", "SELECT" from the menus. Confirm that the chemicals of interest are included among the compounds listed.

- If not listed, a compound must be added to the database by inputting the necessary data in place of another compound already on the list, but not needed for current work. Data on over 700 chemicals are included in the CHEMDAT7 manual. Approximately 300 additional chemicals are included in a companion worksheet, DATATWO.WK1. The "SORT" "DATA" option loads this worksheet. Up to twenty of these chemicals can replace existing chemicals in the CHEMDAT7 worksheet. Make sure that you have already placed a "1" in front of each chemical in the CHEMDAT7 worksheet which you wish to model. Otherwise, the act of importing chemicals using "SORT" "DATA" may overwrite some of the chemicals you wish to model. Place a "1" in front of any chemical you wish to import from DATATWO.WK1 to CHEMDAT7. Press "Alt A" to complete the import process.

- Unfortunately, only a single chemical composition can be considered at a time in CHEMDAT7, so with three different compositions, this example requires three "runs". Select MEK by placing a "1" in column A, zeroing all other chemicals and press "Alt Z".

- Return to the main menu, "Alt M", and select: "DATA-FORMS", "IMPOUND", "NON-AERATED" from the menus to enter the non-aerated impoundment section of the spreadsheet.

- Enter the above data in the appropriate cells. Entering an active biomass of 0 g/l will set biological degradation to zero. CHEMDAT7 will not accept a zero windspeed. For a zero windspeed, use a very small windspeed (0.0001 m/s).

- Complete the calculation by pressing the F9 (calc) key. Results can be viewed or printed as desired by selecting the appropriate option from the main menu. Copies of the CHEMDAT7 printouts generated for the above problem are on pages 3 and 4 of this subsection. The column labeled "EMISS" is the fraction of the chemical inlet loading that is air stripped. Results are summarized below:

	Fraction Vaporized	Emission to Air Mg/yr	Emission to Air lb/yr
MEK	0.094	1.267	2792
MIBK	0.086	1.069	2357
Acetone	0.094	0.073	160

NON-AERATED WASTEWATER TREATMENT

WINDSPEED	4.47 m/s
depth	1.524 m
AREA	837 m2
FLOW	0.0245 m3/s
VO inlet conc.	17.4 mg/l
TOTAL ORGANICS IN	17.4 mg/l
ACTIVE BIOMASS	0 g/l
BIOMASS SOLIDS IN	0 g/l
TEMPERATURE	25 deg. C
AL AIR EMISSIONS	1.27 Mg/yr

COMPOUND NAME	EFFLUENT	EMISS.	BIOL.	PHOTOL. & HYDRO.	ADSORB.	air emiss. (Mg/yr)
METHYL ETHYL KETONE	0.906	0.094	0.000	0.000	0.000	1.2666

NON-AERATED WASTEWATER TREATMENT

WINDSPEED	4.47 m/s
depth	1.524 m
AREA	837 m2
FLOW	0.0245 m3/s
VO inlet conc.	16.1 mg/l
TOTAL ORGANICS IN	16.1 mg/l
ACTIVE BIOMASS	0 g/l
BIOMASS SOLIDS IN	0 g/l
TEMPERATURE	25 deg. C
AL AIR EMISSIONS	1.07 Mg/yr

COMPOUND NAME	EFFLUENT	EMISS.	BIOL.	PHOTOL. & HYDRO.	ADSORB.	air emiss. (Mg/yr)
METHYL ISOBUTYL KETONE	0.914	0.086	0.000	0.000	0.000	1.0693

NON-AERATED WASTEWATER TREATMENT

WINDSPEED	4.47 m/s
depth	1.524 m
AREA	837 m2
FLOW	0.0245 m3/s
VO inlet conc.	1 mg/l
TOTAL ORGANICS IN	1 mg/l
ACTIVE BIOMASS	0 g/l
BIOMASS SOLIDS IN	0 g/l
TEMPERATURE	25 deg. C
AL AIR EMISSIONS	0.07 Mg/yr

COMPOUND NAME		EFFLUENT	EMISS.	BIOL.	PHOTOL. & HYDRO.	ADSORB.	air emiss. (Mg/yr)
ACETONE		0.906	0.094	0.000	0.000	0.000	0.0726

Example Problem 2

Consider an uncovered tank (no oil layer) with the following characteristics:

	English	Metric
Depth	10 ft	3.048 m
Surface Area	20,000 ft^2	1858 m^2
Flow	900 gpm	0.0568 m^3/s
Temperature	77 °F	25 °C
Windspeed	7.25 mph	3.24 m/s

Composition:

Ethylene Glycol	100 mg/l
Phenol	30 mg/l

- For simplicity, the system will be estimated as a single stage.
- Enter the data in exactly the same manner as in Example 1. Again, each chemical must be separately calculated.
- Phenol in included in the basic 61 component set in the CHEMDAT7 worksheet. Ethylene glycol is found in the companion worksheet, DATATWO.WK1. As described in Example 1, insert a "1" in front of phenol, placing "0"'s in front of all other compounds. Next, use "SORT" "DATA" and place a "1" in front of ethylene glycol. Press "Alt A" to import ethylene glycol into CHEMDAT7.
- Copies of the printouts obtained from CHEMDAT7 are on page 2 of this subsection.

The results are summarized below:

	Fraction Vaporized	Emission to Air Mg/yr	Emission to Air lb/yr
Ethylene glycol	0.001	0.154	340
Phenol	0.003	0.165	363

NON-AERATED WASTEWATER TREATMENT	
WINDSPEED	3.24 m/s
depth	3.048 m
AREA	1858 m2
FLOW	0.0568 m3/s
VO inlet conc.	100 mg/l
TOTAL ORGANICS IN	100 mg/l
ACTIVE BIOMASS	0 g/l
BIOMASS SOLIDS IN	0 g/l
TEMPERATURE	25 deg. C
AL AIR EMISSIONS	0.15 Mg/yr

COMPOUND NAME	EFFLUENT	EMISS.	BIOL.	PHOTOL. & HYDRO.	ADSORB.	air emiss. (Mg/yr)
ETHYLENE GLYCOL	0.999	0.001	0.000	0.000	0.000	0.1542

NON-AERATED WASTEWATER TREATMENT	
WINDSPEED	3.24 m/s
depth	3.048 m
AREA	1858 m2
FLOW	0.0568 m3/s
VO inlet conc.	30 mg/l
TOTAL ORGANICS IN	30 mg/l
ACTIVE BIOMASS	0 g/l
BIOMASS SOLIDS IN	0 g/l
TEMPERATURE	25 deg. C
AL AIR EMISSIONS	0.16 Mg/yr

COMPOUND NAME	EFFLUENT	EMISS.	BIOL.	PHOTOL. & HYDRO.	ADSORB.	air emiss. (Mg/yr)
PHENOL	0.997	0.003	0.000	0.000	0.000	0.1649

TRANSFER
OPERATIONS

This section addresses evaporative emission estimates for transfer of hydrocarbons into containers other than stationary storage tanks. Loading, transit, and ballasting losses from tank trucks, rail cars, barges, ocean-going ships, and storage drums will be considered. Emissions from stationary storage tanks is covered in the Tanks Section of this guidebook. Comparative emission factors for petroleum transfer operations can be found in the table on page 010-002.

Loading losses are the primary source of evaporative emissions. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of the residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as new product is being loaded. In determining the quantity of evaporative emissions from loading operations, the following parameters need to be considered:

- Physical characteristics (vapor pressure, molecular weight) of the previous cargo
- Method of loading the new cargo
- Physical characteristics of the new cargo

There are several methods of loading liquid into a cargo tank, and these differ greatly in their effectiveness in generating vapor of the liquid being loaded. These methods include splash loading, submerged loading, and bottom loading. Figure TR.1 illustrates the principle employed with each of these methods. The splash method generates a high degree of turbulence, resulting in a high level of vapor generation. If the turbulence is great enough, liquid droplets can be entrained, and the total hydrocarbon emission can exceed the equilibrium value predicted from the vapor pressure of the liquid. In submerged and bottom loading operations, turbulence is much reduced, and the hydrocarbon released during normal loading operations does not reach the saturated equilibrium level.

The recent loading history of a cargo carrier is also an important factor in determining the emission. If the carrier has carried a non-volatile oil or has just been cleaned, it will initially contain vapor free air. If it has just carried gasoline and has not been vented, the air in the cargo tank will contain volatile organic vapors, which are expelled during the loading operation along with newly generated vapors. In such a circumstance the total weight of hydrocarbon emitted can exceed that predicted from the vapor pressure of the liquid being loaded.

The typical capacities for the container types considered in this section are: marine vessels of up to 20,000 tons, railroad tank cars of 30,000 gallons, tank trucks of 7,000 gallons, and drums of 55 gallons.

For many of the container types, more than one loading emission loss estimating procedure is available. Each of the container types has a simple estimating factor that enables making an estimate with little more information than the type of hydrocarbon being loaded, for example a gasoline. More complicated emission estimating factors require a knowledge of the composition and the temperature of the liquid being loaded and of the loading procedure being used. Still more complicated approaches will require, in addition to liquid composition and temperature, a knowledge of the past voyage of the vessel being loaded.

Most of the evaporative emission estimating procedures in this section are taken from AP-42, 4th Edition, September 1985. This document, in turn is based heavily on API Publications, 2514 and 2514A, which are used in this section as supplemental material.

Figure TR.1

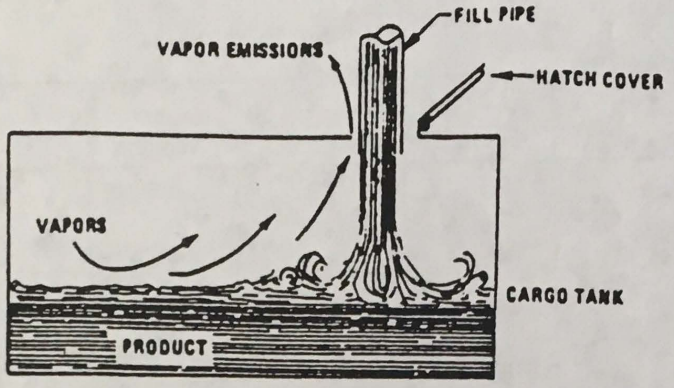


Figure 4.4-2. Splash loading method.

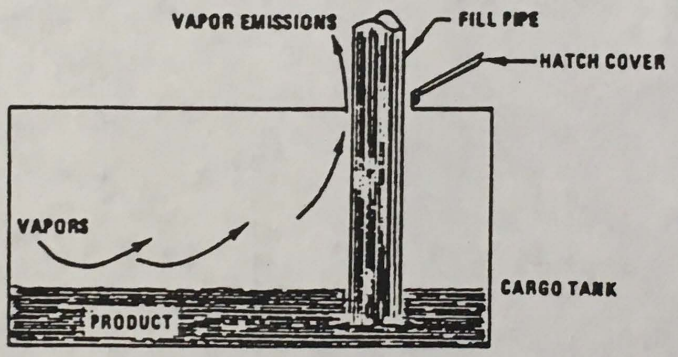


Figure 4.4-3. Submerged fill pipe.

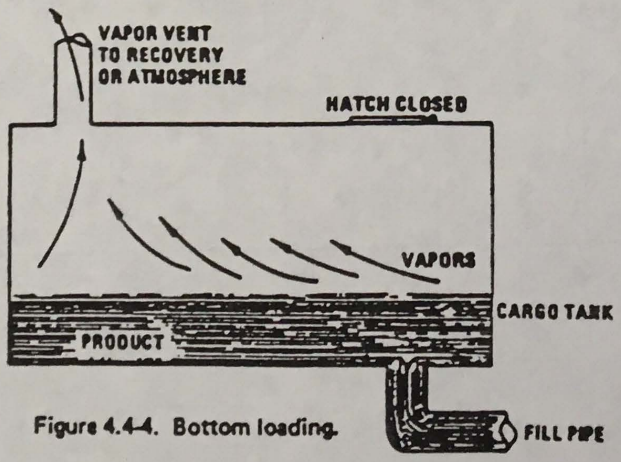


Figure 4.4-4. Bottom loading.

TYPICAL TOTAL ORGANIC EMISSION FACTORS FOR PETROLEUM TRANSFER

Emission Source	Gasoline	Crude Oil	Jet Naphtha	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Rail tank car and tank truck Loading operations						
Submerged loading - dedicated normal service lb/10^3 gal transferred	5	2	1.5	0.16	0.014	0.0001
Submerged loading - vapor balance service lb/10^3 gal transferred	8	3	2.5			
Splash loading - dedicated normal service lb/10^3 gal transferred	12	5	4	0.04	0.03	0.0003
Splash loading - vapor balance service lb/10^3 gal transferred	8	3	2.5			
Ships/ocean barges loading lb/10^3 gal transferred	2	0.61	0.50	0.005	0.005	0.00004
Barges loading lb/10^3 gal transferred	3	1.0	1.2	0.013	0.012	0.00009
Tanker ballasting lb/10^3 gal transferred	0.8	1.1				
Marine Vessel Transit lb/week-10^3 gal transported	2.7	1.3	0.7	0.005	0.005	3×10^{-5}

SECTION	SUBJECT	DATE ISSUED
010-	Introduction	April 93
-001	Transfer Operation Emissions	April 93
-002	Comparative Emissions	April 93
020-	Table of Contents	April 93
030-	Tank Trucks and Railroad Cars	April 93
040-	Marine Loading	April 93
050-	Crude Oil Ballasting	April 93
060-	Retail Service Centers	April 93
070-	Vacuum Truck Loading	April 93
080-	Drums	April 93
090-	Transit Losses	April 93

Emissions from loading petroleum liquids can be estimated (with a probable error of +/- 30%) using the following expression:

$$L_L = \frac{12.46\ SMP^*}{T}$$

where:

L_L = loading loss, lb/1000 gallons of liquid loaded
S = saturation factor, dimensionless (see Table TR.2)
M = molecular weight of vapors, lb/lb mole
P* = true vapor pressure of liquid loaded, psia
T = bulk temperature of liquid loaded, °R (°F + 460)

This expression is similar to the working loss evaporative emission estimates encountered in the Tank Section. The volumetric quantity of vapor emitted is based on an ideal gas law calculation at the temperature and vapor pressure of the liquid being loaded. This ideal emission is multiplied by a saturation factor to adjust for the approach to equilibrium saturation depending on the method of loading used.

If control measures are employed during the loading operation to reduce loading emissions (for example, a vapor recovery, vapor balancing system, or incineration system) then the equation above needs to be multiplied by (1-eff/100), where eff is the efficiency of the control device. These control devices can be highly effective and reductions of 95% in the loading emissions is not uncommon.

TABLE TR.2
S FACTORS FOR CALCULATING LOADING LOSSES[a]

Cargo Carrier	Mode of Operation	S Factor
Tank trucks and tank cars	Submerged loading of a clean cargo tank	0.50
	Splash loading of a clean cargo tank	1.45
	Submerged loading: normal dedicated service	0.60
	Splash loading: normal dedicated service	1.45
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading: dedicated vapor balance service	1.00
Marine vessels[b]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

[a] AP-42, p. 4.4-6.

[b] To be used for products other than gasoline and crude oil.

Sample Calculation - Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8,000 gallons
Gasoline RVP is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95%

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T}\left(1 - \frac{eff}{100}\right)$$

where:

S	=	Saturation factor (see Table TR.2) = 1.00
P	=	True vapor pressure of gasoline (see Tank Section 040-004) = 6.6 psia
M	=	Molecular weight of gasoline vapors (see Tank Section 040-004) = 66
T	=	Temperature of gasoline = 540°R
eff	=	Control efficiency = 95%

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540}\left(1 - \frac{95}{100}\right)$$

$= 0.50$ lb/10^3 gal

Total loading losses are:

(0.50 lb/10^3 gal) (8.0 x 10^3 gal) = 4.0 lb

The following sample calculation illustrates an estimate of organic emissions from tank truck loading of an organic liquid. Waste stream compounds and properties for the sample calculation are:

Constituent	Weight Fraction	Molecular Weight (lb/mole)	Vapor Pressure (psia)	Mole Fraction
Benzene	0.3	78	1.84	0.368
Naphthalene	0.3	128	0.0044	0.224
Phenol	0.4	94	0.0066	0.408

The input parameters for the truck loading model are:

- True vapor pressure of loading liquid, psia: 0.68 (calculated in a., below)
- Molecular weight of vapor, lb/mole: 78.23 (calculated in b., below)
- Saturation factor, dimensionless: 1.45 (splash loading)
- Annual throughput, gal/yr: 28,000

a. Calculate P*, true vapor pressure of liquid, by Raoult's Law:

$$P^* = P_1 \cdot X_1 + P_2 \cdot X_2 + P_3 \cdot X_3$$

where:

P^* = true vapor pressure, psia
P_1, P_2 and P_3 = vapor pressures of pure chemicals, psia
X_1, X_2 and X_3 = mole fractions of VOC chemicals in liquid
P^* = (1.84 x 0.368) + (0.0044 x 0.224) + (0.0066 x 0.408)
= 0.68 psia

b. Calculate M, molecular weight of vapors:

$$M = \frac{(P_1 \cdot X_1)}{P^*} \cdot M_1 + \frac{(P_2 \cdot X_2)}{P^*} \cdot M_2 + \frac{(P_3 \cdot X_3)}{P^*} \cdot M_3$$

where:

M = molecular weight of vapor, lb/lb mole
M_1, M_2, and M_3 = molecular weight of each chemical

$$M = \frac{1.84 \times 0.368}{0.68} \times 78 + \frac{0.0044 \times 0.224}{0.68} + 128 + \frac{0.0066 \times 0.408}{0.68} \times 94$$

$$= 78.23 \text{ lb/mole}$$

c. Calculate emissions from truck loading:

$$L_L = \frac{12.46 \text{ SMP*}}{T}$$

$$= \frac{12.46 \times 1.45 \times 78.23 \times 0.68}{528}$$

$$= 1.8 \text{ lb/1,000 gal}$$

Annual emissions $= 1.8 \times 10^{-3}$ lb/gal x 28,000 gal/yr
$= 51$ lbs/yr

Marine loading emission estimates are given separately for barges and for tankers. The estimates in this guidebook are applicable to ocean going barges and to crude oil tankers smaller than VLCC in size not employing crude-oil washing of the cargo tanks.

Three levels of emission estimating factors are provided with separate factors given for gasoline and crude oil loading. The simplest factor (Level 1) requires only a knowledge of the liquid loaded (gasoline or crude oil) and the type of vessel being loaded (tanker or barge). At the next stage (Level 2) general information on the prior cargo and the condition of the cargo tank being loaded is required.

In Level 3, the evaporative loss is divided into an "on-arrival loss" which reflects the general characteristics of the prior cargo and the condition of the cargo tanks being loaded, and a "generated loss" that considers vapor pressure, molecular weight, of the liquid being loaded and the temperature of the vapor. Equations are provided in AP-42 to calculate each of these losses separately. API Publication 2514A provides a graphical method to obtain the generated emissions once the vapor pressure of the liquid is known.

MARINE LOADING LOSSES - LEVEL 1 FACTORS

GASOLINE LOADING

TANKERS:	1.8 POUNDS/1000 GALLONS LOADED
BARGES:	3.4 POUNDS/1000 GALLONS LOADED

CRUDE OIL LOADING

TANKERS/BARGES:	1.0 POUNDS/1000 GALLONS LOADED

GASOLINE LOADING LOSSES - LEVEL 2

VESSEL	PRIOR CARGO	COMPARTMENT TREATMENT DURING BALLAST VOYAGE	EMISSION FACTOR (POUNDS/1000 GAL LOADED)
TANKER/OCEAN BARGE	VOLATILE*	UNCLEANED	2.6
TANKER/OCEAN BARGE	VOLATILE	BALLASTED	1.7
TANKER/OCEAN BARGE	VOLATILE	CLEANED	1.5
TANKER/OCEAN BARGE	VOLATILE	GAS FREED	0.7
	NON-VOLATILE	BALLASTED, GAS FREED, CLEANED, UNCLEANED	0.7
BARGE	VOLATILE	UNCLEANED	3.9
BARGE	VOLATILE	CLEANED, GAS FREED	2.0
	NON-VOLATILE	UNCLEANED, CLEANED, GAS FREED	2.0

* VOLATILE CARGOES ARE THOSE WITH TVP GREATER THAN 1.5 PSI

CRUDE OIL LOADING LOSSES - LEVEL 2

PRIOR CARGO	COMPARTMENT TREATMENT DURING BALLAST VOYAGE	EMISSION FACTOR (POUNDS/1000 GAL LOADED)
VOLATILE*	UNCLEANED	1.1
VOLATILE	BALLASTED	0.7
VOLATILE	CLEANED, GAS FREED	0.6
NON-VOLATILE	BALLASTED, CLEANED, GAS FREED, UNCLEANED	0.6

* VOLATILE CARGOES ARE THOSE WITH TVP GREATER THAN 1.5 PSI

The following equation has been developed specifically for estimating the emissions from the loading of crude oil into ships and ocean barges:

$$C_L = C_A + C_G$$

where:

C_L = Total loading loss, lb/10^3 gal of crude oil loaded
C_A = Arrival emission factor, contributed by vapors in the empty tank compartment prior to loading, lb/10^3 gal loaded (see Note)
C_G = Generated emission factor, contributed by evaporation during loading, lb/10^3 gal loaded

This equation was developed empirically based on test measurements of several vessel compartments. The quantity C_G can be calculated using:

$$C_G = 1.84\ (0.44\ P - 0.42)\ \frac{MG}{T}$$

where:

P = True vapor pressure of loaded crude oil, psia (see Tanks Section 040-004)
M = Molecular weight of vapors, lb/lb-mole (see Tanks Section 040-004)
G = Vapor growth factor = 1.02 (dimensionless)
T = Temperature of vapors, °R (°F + 460)

Note: Values of C_A for various cargo tank conditions are listed below:

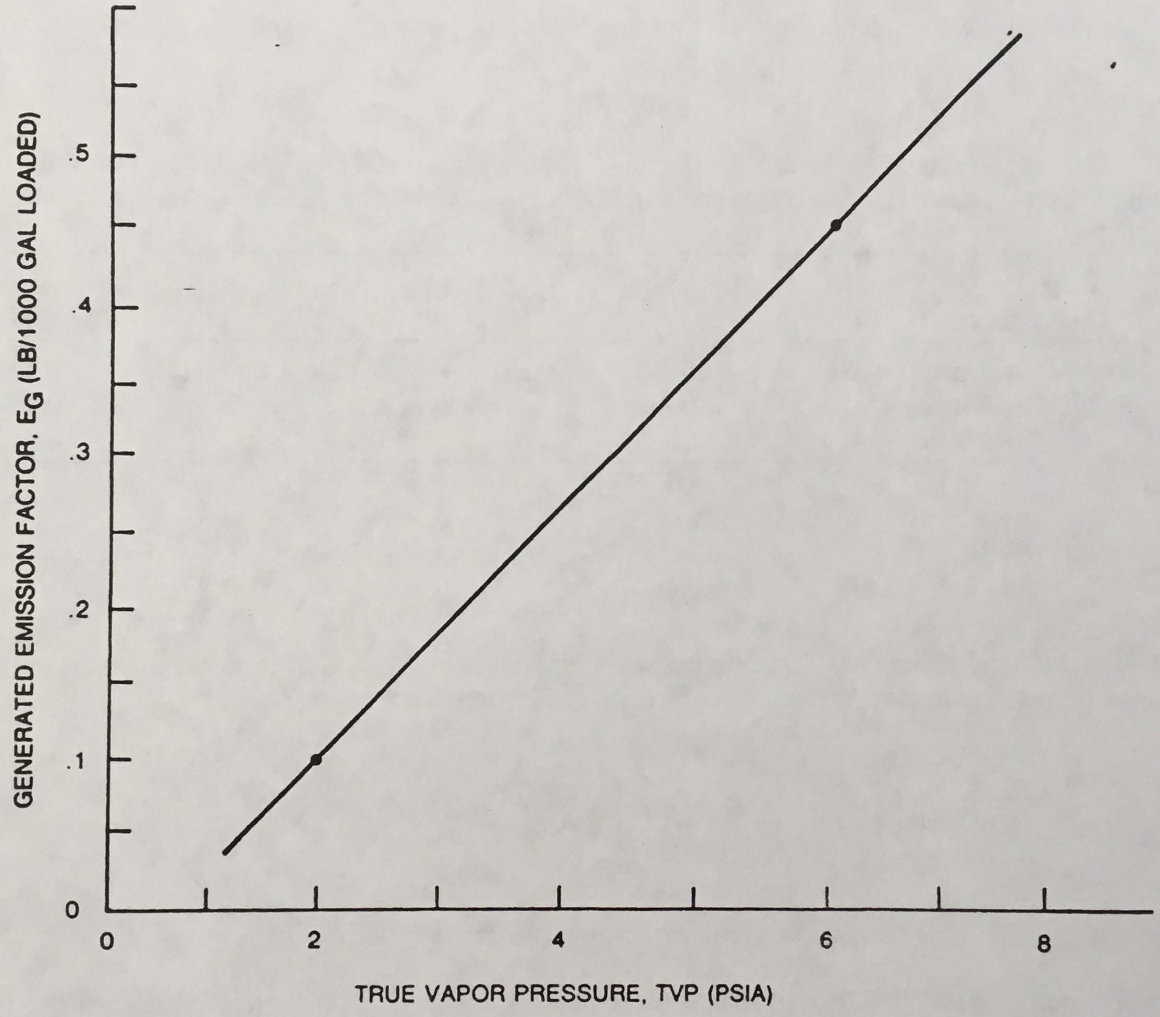
CRUDE OIL ARRIVAL EMISSION FACTOR

PRIOR CARGO	COMPARTMENT TREATMENT DURING BALLAST VOYAGE	EMISSION FACTOR (POUNDS/1000 GAL LOADED)
VOLATILE	UNCLEANED	0.86
VOLATILE	BALLASTED	0.46
VOLATILE	CLEANED	0.33
VOLATILE	GAS FREED	0.33
NON-VOLATILE	BALLASTED, CLEANED, GAS FREED, UNCLEANED	0.33

Emission factors derived from the above equations represent total organic compounds. Nonmethane-nonethane volatile organic compound (VOC) emission factors for crude oil vapors have been found to range from approximately 55 to 100 weight percent of these total organic factors. When specific vapor composition information is not available, the VOC emission factor can be estimated by taking 85 percent of the total organic factor.

Figure TR.3

Generate Emission Factor for Crude Oil Loading



NOTE: Based on average values of *M*, *G*, and *T* from Table 3.

Problem No. 1: Gasoline Loading

Vessel description: 30,000 dead-weight-ton tanker, loading 125,000 barrels of motor gasoline; all compartments receiving gasoline previously carried volatile cargo.

Compartment arrival conditions: 25 percent uncleaned, 10 percent ballasted, and 65 percent gas-freed.

Solution:

Using the average emission factors for Level 2 from Page 040-003 in this section and the vessel arrival conditions given, a weighted average emission factor is determined as shown below:

Prior Cargo Category	Prior Cargo Percent	Average Factor (lb/1000 gal)	Weighted Factor (lb/1000 gal)
volatile, uncleaned	25	2.6	0.65
volatile, ballasted	10	1.7	0.17
volatile, gas freed	65	0.7	0.46
			1.28 or 1.3 lb/1000 gal

Calculate the total emissions, T_{HC}, in tons by multiplying the weighted average emission factor by the total volume of gasoline loaded (including appropriate conversion factors):

$$T_{HC} = \left[\frac{1.3lb}{1000gal}\right]\left[\frac{ton}{2000lb}\right](125{,}000bbl)\left[42\frac{gal}{bbl}\right]$$

$= 3.4$ ton

Problem No. 2: Crude Oil Loading (crude oil vapor pressure is not available)

Vessel description: 30,000 dead-weight-ton tanker, loading 180,000 barrels of domestic crude oil; all compartments previously carried volatile crude oil.

Compartment arrival conditions: 85 percent uncleaned and 15 percent cleaned.

Solution, Case A - Crude Oil Vapor Pressure Not Available

Using the average emission factors from Page 040-003, and the vessel arrival conditions given, a weighted average emission factor is determined as shown below:

Prior Cargo Category	Prior Cargo Percent	Average Factor (lb/1000 gal)	Weighted Factor (lb/1000 gal)
volatile, uncleaned	85	1.1	0.94
volatile, cleaned	15	0.6	0.09
			1.03 or 1.0 lb/1000 gal

Calculate the total emissions, T_{HC}, in tons by multiplying the weighted average emission factor by the total volume of crude oil loaded (including appropriate conversion factors):

$$T_{HC} = \left[\frac{1.0lb}{1000gal}\right]\left[\frac{ton}{2000lb}\right](180{,}000bbl)\left[42\frac{gal}{bbl}\right]$$

$= 3.8$ tons

Solution, Case B - Crude Oil Vapor Pressure Available

Assume the same vessel and arrival conditions as given above. Also, assume that the crude oil has a Reid vapor pressure of 4 pounds per square inch and is loaded at 60°F (520°R). Using this information, a better estimate of emissions can be made than shown in Case A.

To determine the total emissions, T_{HC}, the arrival and generated emission factors must first be determined.

The arrival emission factor, E_A, on the average, was not found to be dependent on vapor pressure. From Table 2, the average arrival factors for Categories uncleaned and ballasted are 0.86 and 0.33 pounds per 1000 gallons, respectively.

The generated emission factor, E_G, is dependent upon the true vapor pressure of the crude oil. From Tank Section 040-004, true vapor pressure equals 2.0 pounds per square inch absolute, for a Reid vapor pressure of 4.0 pounds per square inch and a cargo temperature of 60°F. E_G can be read from Figure TR.3 or calculated from the equation on page 040-004 of this section, assuming an average vapor molecular weight of 58 pounds per pound-mole and an average vapor growth factor of 1.02 from Table 3.

$$E_G = 1.84[0.44(2.0) - 0.42]\frac{(58)(1.02}{(520)}$$

$= 0.10$ lb/1000 gal

The total emission factor, E_T, is determined for each category from Equation 1. A weighted average emission factor for the total loading operation is determined from the total emission factors for each category and the given vessel arrival conditions, as shown:

Prior Cargo Category	E_A	E_G	E_T	Prior Cargo Percent	Weighted Factor (lb/1000 gal)
uncleaned	0.86	0.10	0.96	85	0.82
cleaned	0.33	0.10	0.43	15	0.06
					0.88 or 0.9 lb/1000 gal

Calculate the total emissions, T_{HC}, as in 1.3.2.2:

$$T_{HC} = \left[\frac{0.9lb}{1000gal}\right]\left[\frac{ton}{2000lb}\right](180{,}000bbl)\left[42\frac{gal}{bbl}\right]$$

$= 3.4$ tons

Reference: Problems taken from API Publications 2514A, 2nd Edition, September 1981.

Emissions from crude oil ballasting operations are associated with crude oil unloading rather than with the loading operations discussed earlier. It is common practice to load several cargo tank compartments with sea water after the cargo has been unloaded. This water, termed ballast, improves the stability of the empty tanker during the subsequent voyage. Although ballasting procedures vary, individual cargo tanks are typically ballasted about 80%, and the total vessel is ballasted 15 to 40% of capacity. Emissions from crude ballasting operations may have to be included in the site emission estimate depending on where the ballasting physically occurs.

Like in earlier gasoline and crude oil loading, the loading of the ballast water displaces a corresponding volume of vapors, which are subsequently emitted to the atmosphere. There are three levels of emission estimating factors for crude ballasting, each of which requires an increasing amount of information on the cargo and the past history of the vessel.

EMISSIONS FROM CRUDE OIL BALLASTING

LEVEL 1

1.4 POUNDS/1000 GALLONS BALLAST WATER LOADED

LEVEL 2

COMPARTMENT CONDITION PRIOR TO CARGO DISCHARGE	EMISSION FACTOR (POUNDS/1000 GAL BALLAST LOADED)
FULLY LOADED (LESS THAN 5 FT. ULLAGE)	1.2
LIGHTERED OR PREVIOUSLY SHORT LOADED	1.9

The following equation has been developed from test data to calculate the ballasting emissions from crude oil ships and ocean barges:

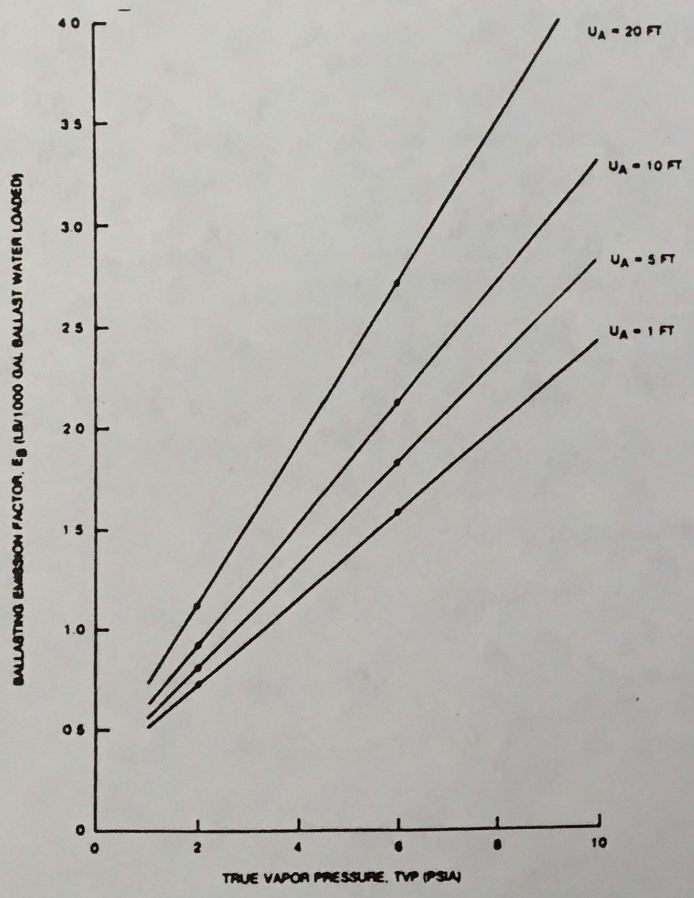
$$E_B = 0.31 + 0.20\,P + 0.01\,PU_A$$

where: E_B = Ballasting emission factor, lb/10^3 gal of ballast water

P = True vapor pressure of discharged crude oil, psia (see Figure 8 and Table 6 in Tanks Section 040-004)

U_A = Arrival cargo true ullage, prior to dockside discharge, measured from the deck, feet. The term "ullage" refers to the distance between the cargo surface level and the deck level.

A graphical solution for the ballasting emission factor is given below.



Sample Calculation - Ballasting emissions from a crude oil cargo ship would be calculated as follows, using Equation 4:

Design basis -

Vessel and cargo description:
80,000 dead-weight-ton tanker, crude oil capacity 500,000 barrels;
20 percent of the cargo capacity is filled with ballast water after cargo discharge. The crude oil has an RVP of 6 psia and is discharged at 75°F.

Compartment conditions:
70 percent of the ballast water is loaded into compartments that had been fully loaded to 2 feet ullage, and 30 percent is loaded into compartments that had been lightered to 15 feet ullage before arrival at dockside.

Ballasting emission equation -

$$E_B = 0.31 + 0.20\,P + 0.01\,PU_A$$

where:

P = true vapor pressure of crude oil (see Figure 8 in Tanks Section 040-004)
= 4.6 psia

U_A = True cargo ullage for the full compartments = 2 feet, and true cargo ullage for the lightered compartments = 15 feet

$$E_B = 0.70\,[0.31 + (0.20)(4.6) + (0.01)(4.6)(2)] + 0.30\,[0.31 + (0.20)(4.6) + (0.01)(4.6)(15)]$$

$$= 1.5 \text{ lb}/10^3 \text{ gal}$$

Total ballasting emissions are:

$$(1.5 \text{ lb}/10^3 \text{ gal})(0.20)(500{,}000 \text{ bbl})(42 \text{ gal/bbl}) = 6{,}300 \text{ lb}$$

Since VOC emissions average about 85% of these total organic emissions, emissions of VOC are about: (0.85)(6,300 lb) = 5,360 lb

There are two transfer operation evaporative emissions associated with retail service stations. The first is the filling of the underground storage tank at the retail center. The second is the refueling of the motor vehicle. In each case a liquid is transferred to fill a container, displacing in the process the vapors in the space to be filled.

In retail service center transfer operations we have a dedicated product service, and the hydrocarbon liquid being loaded, for example gasoline, already saturates the vapor space. It only requires consideration of the loading method (splash or submerged) to estimate the uncontrolled evaporative emission using the equation given in Section 030 on tank truck and railroad car loading.

Control measures to reduce evaporative emissions in gasoline service center operations, such as natural or vacuum assisted vapor balancing, are now required in the United States. Tests on these systems have indicated overall system control efficiencies in the range of 88 to 92 percent. Correction for a reduction in the evaporative emission must be made when these control measures are used.

Emission Estimating Guide	Transfer Operation 060-002
Section: Gasoline Service Center Operations	**Subject:** Emission Factors

EMISSIONS FROM RETAIL FACILITIES

	EMISSIONS RATE (POUNDS/1000 GALLONS THROUGHPUT)
FILLING UNDERGROUND TANKS	
SUBMERGED FILLING*	7.3
SPLASH FILLING*	11.5
VAPOR BALANCE SYSTEM	0.3
UNDERGROUND TANK BREATHING	1.0
VEHICLE REFUELING	
DISPLACEMENT LOSSES (UNCONTROLLED)	11.0
DISPLACEMENT LOSSES (CONTROLLED)	1.1
SPILLAGE	0.7

* RVP = 10 PSIA

Emission Estimating Guide	Transfer Operation 070-001
Section: Vacuum Truck Loading	**Subject:** Background

Emissions from vacuum truck loading are estimated by calculating an equilibrium concentration of organic vapors in the vacuum truck at its operating conditions and assuming that a total volume of gas equal to the vacuum truck volume is emitted to the atmosphere for each loading episode.

Model Parameters

Based on information EPA obtained during site visits to refineries, vacuum trucks have a capacity of approximately 5,500 gallons (735 ft^3) and operate at a pressure of approximately 6 psia. These values are used in estimating vacuum truck emissions.

Molecular weight and vapor pressure are functions of material loaded, and 68°F is considered a standard operating temperature.

Equations for estimating emissions from vacuum truck loading are presented as follows:

$$E_i = N_v \times Y_i \times MW_i$$

$$Y_i = \frac{X_i P^*}{P_t} \text{ (for oily waste)}$$

$$N_v = \frac{V}{[P_o V_G (T/492)]/P_t}$$

where:

E_i = air emissions of compound i, lb/truckload

N_v = total moles of vapor discharged, lb mole

Y_i = mole fraction of compound i in vapor phase

X_i = mole fraction of compound i in liquid phase

MW_i = molecular weight of compound i, lb/lb mole

P^* = vapor pressure of compound i, psia

P_t = total system operating pressure, psia

P_o = atmospheric pressure, psia

V = vacuum truck volume, ft^3

V_G = volume of 1 g mole of gas at 68°F, 1 atm: 385 ft^3/lb mole

T = operating temperature, °R

The following is a sample calculation of benzene emissions during loading of a vacuum truck with organic liquid.

Input parameters:

MW_i, molecular weight, lb/lb mole: 78

P*, pure compound vapor pressure psia: 1.8

P_t, System operating pressure, psia: 6

P_o, atmospheric pressure, psia: 14.7

X_i, mole fraction in liquid: 0.368

V, vacuum truck volume, ft^3: 735 ft^3

V_G, volume of 1 lb mole of gas at 68°F 1 atm, ft^3/lb mole: 385

T, operating temperature, R: 528

N, turnovers per year, truckload/yr: 10

a. Calculate total moles of vapor discharged, lb mole:

$$N_v = \frac{V}{[P_o V_G (T/492)]/P_t}$$

$$= \frac{735\ ft^3}{[14.7\ psia \times 385\ ft^3/lb\ mole \times 528\ R/492\ R]/6\ psia}$$

$$= 0.8\ lb\ mole/truckload$$

b. Calculate mole fraction of benzene in vapor phase, Y_i:

$$Y_i = \frac{P^* X_i}{P_t} = \frac{1.8 \times 0.37}{6} = 0.11$$

c. Calculate air emissions per truckload, lb/truckload:

$E_i = N_v \times Y_i \times MW_i$

= (0.8 lb mole/truckload) x (0.11) x (78 lb/lb mole)

= 6.9 lb/truckload

d. Calculate annual emissions for benzene, lb/yr:

Annual emission = $E_i \times N$
= 6.9 lb/truckload x 10 truckload/yr
= 69 lb/yr

In addition to loading and ballasting losses , losses occur while the cargo is in transit. Transit losses are similar in many ways to breathing losses associated with storage tanks. As the temperature of the cargo container changes during the day, vapors are expelled from the vapor space to yield hydrocarbon emissions.

AP-42 indicates that transit losses on ships and barges can be calculated by the following equation:

$$L_T = 0.1\ PW$$

where:
- L_T = Transit loss from ships and barges, lb/week-10^3 gal transported
- P = True vapor pressure of the transported liquid, psia (see Figures 5 and 8 in Tanks Section 040-004)
- W = Density of the condensed vapors, lb/gal (see Table 7 in Tanks Section 040-004)



IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: INFORMATION MANAGEMENT SYSTEM

SUBJECT: OVERVIEW

INTRODUCTION

In this section EIS refers to the specific Environmental Information System distributed by Oracle. IOL may evaluate the purchase of an EIS license in late 1993. Should IOL acquire a license, appropriate support systems will be developed.

This Section provides a general introduction to the EIS system. It can be used by anyone who requires an overview of the EIS system and who requires information about how to access EIS.

EIS MODULES

The EIS system is divided into several modules. They are as follows:

MATERIAL	GENERAL
PLANT	REGULATION
EQUIPMENT	PERMIT
AIR	EVENT
WATER	ANALYTICAL
GROUNDWATER	TICKLER
SOLID WASTE	PROJECT
EMU	

MATERIAL MODULE

The MATERIAL MODULE provides the ability to store information about materials that will impact environmental management and reporting done by the Plant, Regulations, Air, Water and Solid Waste modules. Included are NPRI listed chemicals, physical properties, products, streams, and purchased materials. Components are specified for complex materials to identify NPRI listed chemicals. Tracking hazardous substances is also possible.

INFORMATION MANAGEMENT SYSTEM	OVERVIEW

PLANT MODULE

The PLANT MODULE provides the ability to store extensive information on the physical, administrative and personnel aspects of the plants. It is the basis for environmental reporting on sites, divisions, departments, business partners, and environmental contact. Climatological data required for calculating emissions is stored with the plant data.

EQUIPMENT MODULE

The EQUIPMENT MODULE provides the ability to store specifications on hardware equipment or systems used at the site that have relevance to emissions reporting environmental activities such as air treatment devices, cooling towers, flares, stacks, vents, storage tanks, combustion units, and water monitoring devices. The equipment information stored here is used for calculating emissions.

AIR MODULE

The AIR MODULE identifies air emissions, including storage tank, vessel, emissions control equipment, fugitive, loading/drumming and combustion. It calculates air emissions based on information in the MATERIAL, PLANT, and EQUIPMENT modules.

WATER MODULE

The WATER MODULE helps handle discharged water streams providing units that allow:

- characterizing water streams in detail
- identifying and tracking discharge outfall locations at a site
- identifying major water stream treating devices
- inventorying water discharge to minimize waste and
- recharging treated water.

GROUNDWATER MODULE

The GROUNDWATER MODULE makes it easy to track, list and describe bore holes (groundwater wells and soil borings) and to identify bore holes by soil/rock material type and record comments on water bearing zones.

IMPERIAL OIL LIMITED - ENVIRONMENTAL RELEASE INVENTORY GUIDELINE

SECTION: INFORMATION MANAGEMENT SYSTEM

SUBJECT: OVERVIEW

SOLID WASTE MODULE

The SOLID WASTE MODULE helps characterize and track the route of solid streams whether to an incinerator, boiler, landfill, dewatering facility, water treatment plant or other facility. It can also record inspection information and automatically generate an inventory of solid streams waiting for treatment or disposals.

EMU MODULE

The EMU (Environmental Management Unit) MODULE permits the tracking of information related to equipment, units or systems used for waste processing. The module allows the recording of static or historical information needed to track and report on the treatment, storage, disposal or recycling of process wastes in accordance with local, provincial or federal regulations.

GENERAL MODULE

The GENERAL MODULE maintains information used by other Oracle EIS modules. For example:

- Oracle EIS module reference codes
- time span
- unit measure conversion
- geographic unit
- user security
- glossary of environmental terms/acronyms and
- standard text paragraphs for reporting.

REGULATION

The REGULATION MODULE maintains a range of information on environmental protection regulations and regulatory bodies. It makes it easy to determine the impact of any regulation on specific planned operations or on the company as a whole. It also identifies reportable chemicals and thresholds.

PERMIT MODULE	With the PERMIT MODULE it is easy to log and track permits, from application to amendments and renewal. The module stores extensive data, including effective and expiration dates, fees, items regulated by the permit and compliance requirements.
EVENT MODULE	The EVENT MODULE tracks environmental events such as spills, air violations, water compliance or citizen complaints. With this information it will be easy to determine the impact of a particular event on current regulations, projects or permits. The module tracks event type and items and material involved. It can contain a complete record of the event including corrective actions, impacted regulations or permits, event causes and related events.
ANALYTICAL MODULE	The ANALYTICAL MODULE makes it easy to identify and track analytical sampling specified by other modules; e.g., where measured or monitored data is used or required for emission calculations.
TICKLER MODULE	By tracking significant activities and dates in the TICKLER MODULE, it can be set to generate automatic reminders for individuals or groups of users. Reminders include activities related to permits, events, or regulatory reports.
PROJECT MODULE	The PROJECT MODULE tracks information on various environmental projects and activities such as capital or expense projects. site assessments or waste minimization. It permits the easy compilation of reports.


A

PURPOSE & OBJECTIVES

The purpose of this project is to define, design and implement a generic model for developing a Broad Imperial Pollutant Inventory (BIPI). The BIPI model will support a common approach within the company for tracking and reporting the releases associated with IOL operations to meet regulatory, policy and business needs, including:

- Environment Canada's initiative under the Canadian Environmental Protection Act to compile a National Pollutant Release Inventory (NPRI)
- IOL's environmental policy and OIMS elements requiring that environmental hazards associated with the company's activities are identified, assessed and managed
- business initiatives such as CPPA's National Emissions Reduction Master plan (NERM), ECC's Emission and Waste Reduction Program and the generally increasing community expectations in this area.

CORPORATE APPROACH

The objectives of pursuing an integrated approach within IOL are to:

- reduce the operational impacts and costs for response to regulatory (eg: NPRI), industry (eg: NERM) and corporate (eg: OIMS) pollutant management initiatives by minimizing redundant initial and ongoing effort
- capture the benefits and synergies of bringing broad business/technical perspectives together to define BIPI requirements and identify solutions while maintaining enough flexibility to accommodate divisional differences
- improve the quality and consistency of internal/external pollutant reporting and communications by applying consistent assumptions, definitions, methods and information systems tools throughout the company.

The driving forces for a developing a common approach within IOL include:

- clear management expectations that IOL divisions will cooperate on "macro processes" within the company to minimize duplication of systems and costs (C.I. Council)

CORPORATE APPROACH (CONT'D)

- resource constraints within EH&S functions and in all operations for this non-discretionary activity and severe time constraints associated with NPRI reporting
- consistent external IOL communications will minimize liabilities, community concerns and potential impacts on the company's public image and profitability.

PROJECT SCOPE

The project includes the products of three phases - definition, design and implementation - as described below. It does not include post-implementation activities such as corporate summations and communications, release reduction strategies, tracking of site reduction, reuse and recycling programs and tracking and/or external reporting other than for NPRI/NERM requirements.

DEFINITION PHASE DELIVERABLES

The definition phase will be completed by the end of February 1993 and includes recommendations for:

- an inventory framework based on regulatory, policy and business requirements
- a common set of definitions, guidelines and methodologies
- an information support strategy for identifying and quantifying use of substances (existing data)
- a recommendation for an information system to compile release data and generate related reports
- divisional plans to complete implementation by the end of 1993
- cost/benefit analyses and documentation for the project.

DESIGN PHASE DELIVERABLES

The design phase will be completed by the end of March 1993 and includes the creation or acquisition of generic implementation support tools based on the approved project definition, specifically:

- generic documentation of procedures and release and quantification methodologies (ie: BIPI Manual)
- business validation process for approval and purchase of recommended information system
- any additional documentation required by the divisions for training and implementation (e.g.: Refinery Implementation Guide).

IMPLEMENTATION PHASE DELIVERABLES

The implementation phase will be completed independently in each division by the end of 1993 and includes:

- o training and support of site personnel as needed
- o collection of specified inventory information for 1993 releases at designated IOL sites/operations
- o installation of information system and site data loads
- o divisional capability in place for future inventory compilation or update.

ORGANIZATION TO DELIVER

The following organization is in place for the BIPI project:

- o The IOL Environmental Health and Safety Committee is the project sponsor, providing overall direction to the project team and approving recommendations and expenditures for the definition and design phases. Divisional representatives on this committee support communication with and related approvals by business managers within their respective organizations.

- o The BIPI project team is composed of representatives from each operating division, informations systems resources from the CSD Occupational Health Division and technical resources from Sarnia Research Department. This team is responsible for delivering project products consistent with the mandate and objectives and for ensuring related industry/government participation and communication and coordination with related activities in affiliate networks. Additional support is drawn from the implementation network as required.

- o An implementation network composed of the project team representatives for each operating division and their respective business unit/site BIPI coordinators is responsible for input of business and technical requirements to the definition and design phases and, subsequently, for leading the implementation in their respective sites/units. The implementation network will assume ownership of all system elements upon completion of rollout and be responsible for ongoing updates.

COST/BENEFIT ASSUMPTIONS

The assumptions for the cost/benefit analysis are detailed in section 060. They are largely derived from U.S. Exxon affiliate experiences in implementing similar legislation.

TOTAL PROJECT COST ESTIMATES

	Total		Distributed K$		
	W/M	K$	IOC	IOP	IOR
Definition/Design	22	297	55	173	69
Implementation	183	2011	102	1565	343
Total Resource	205	2308	157	1738	412
Software License		258	52	129	77
Total Project	205	2566	209	1867	489

BENEFITS

Project benefits for this non-discretionary activity are derived from two areas - those related to taking an integrated corporate approach and those related to the business savings that can be achieved by using the comprehensive release inventory as a basis for ongoing release management and regulatory/community response.

Reduced one-time costs for NPRI/other regulatory and policy compliance achieved by taking a common approach within IOL, including IS costs	140 K
Annual maintenance and support costs savings of shared methodologies, documentation and information systems tools	480 K
Annual communications analyses/alignment cost savings of implementing consistent reporting basis and shared database	50 K
Annual cost savings of improved release management and regulatory/community response capability for new requirements and issues	500 K
Ongoing central maintenance and support costs	(150)K
Ongoing site inventory maintenance/reporting costs	(500)K
Net benefit	520 K

Several qualitative benefits were also identified by the project team. These include improved overall quality of IOL's pollutant inventory information, improved security and continuity over the environment for storing this proprietary data, better alignment with affiliate network efforts in this area and improved consistency of internal and external communications.

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APPENDICES

I. Inventory Parameters Detail

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V Exxon Learnings Summary

PURPOSE

In October, 1992, Imperial Oil's Environmental Health and Safety committee sponsored a project to define and design a synergistic approach to compiling release inventories that meet business needs in an effective and timely manner.

A project team was assembled composed of representatives from the Products, Chemicals and Resources Divisions as well as representatives of the management company. The team's mandate was to "deliver a management system that tracks and measures IOL's releases to the environment to meet business needs". IOL Divisions were the clients of this work.

This document:

- o describes the products of the definition phase of the project and provides a basis for approvals for developing tools, acquiring information systems and implementing the pollutant inventory across IOL
- o provides a game plan for the project team, and
- o meets corporate standards for project documentation.

DRIVING FORCES

The pollutant inventory will meet policy, regulatory and business needs.

POLICY

Elements of Imperial's policies and environmental strategic framework require that "environmental hazards associated with company activities are identified, assessed and managed.

Similarly, an element of the Operations Integrity Management Framework is described as "A system is in place to identify hazards, assess consequences and probabilities, and evaluate prevention and mitigation measures for the ongoing management of risk."

The pollutant inventory will consolidate information on releases of hazardous substances, as well as conventional pollutants.

REGULATORY

Environment Canada will be compiling a National Pollutant Release Inventory (NPRI). Each year, under authority of Section 16 of the Canadian Environmental Protection Act, it will request, any facility with 10 or more employees to submit a report for each substance on the NPRI list manufactured (including as a byproduct), produced or otherwise used in excess of 10,000 kg per year. The report will include releases to all media (air, water, soil, underground). 1993 releases are to be reported in early 1994.

The data from the NPRI will be used by other federal programs such as the Accelerated Reduction or Elimination of Toxics (ARET), Pollution Prevention and the initiatives to address ground level ozone.

BUSINESS

Under their Responsible Care commitment, all Canadian Chemical Producers Association member companies are required to participate in a National Emissions Reduction Master plan (NERM). The first step of the plan is to develop multimedia emissions inventories. The federal NPRI program design was based on NERM and the US Toxic Release Inventory (TRI).

Chemicals Division is also required to contribute to the Exxon Chemical Emission and Waste Reduction Program.

The inventory data will be used by Imperial facilities to:

- better understand hazardous releases from their sites, so that they may be assessed and managed appropriately, considering the national context
- establish a base case against which to measure progress
- improve discussions with regulatory agencies
- improve community relations and public image.

PURPOSE

A a common corporate approach is being taken to the definition and design phases. This will:

- reduce the operational impacts and costs for response to regulatory (e.g. NPRI), industry (e.g. NERM) and corporate (e.g. OIMS) pollutant management initiatives by minimizing redundant initial and ongoing effort between and within Imperial divisions.
- capture the benefits and synergy of bringing broad business/technical perspectives together to define requirements and identify solutions while maintaining enough flexibility to accommodate divisional differences
- improve the quality and consistency of internal/external pollutant reporting and communications by applying consistent assumptions, definitions, methods and information systems tools throughout the company.

DRIVING FORCES

The driving forces for developing a common corporate approach include:

- management expectations that IOL divisions will cooperate on "macro processes" within the company to minimize duplication of systems and costs (C.I Council)
- resource constraints within all operations for this non-discretionary activity and severe time constraints associated with NPRI reporting
- requirements for every division to document hazardous emissions for government audits
- consistent external IOL communications will minimize liabilities, community concerns and potential impacts on the company's public image and profitability.

THREE PHASES

The project has three distinct phases: definition, design and implementation.

DEFINITION PHASE

The definition phase includes recommendations for:

- an inventory framework based on regulatory, business and policy needs
- a common set of definitions, guidelines and methodologies to assist sites
- an information support strategy for identifying and quantifying use of substances
- an information system to compile release data and generate reports
- a plan to complete implementation by the end of 1993.

This document is the product of the definition phase.

DESIGN PHASE

The design phase will direct the creation and purchase of support tools based on the strategies outlined in the design phase. Components of the design phase are delineated in Section 4, Design Phase Deliverables. The design phase will be complete by March 31, 1993.

IMPLEMENTATION PHASE

The final major phase implements the strategies of the definition phase using the tools of the design phase. The elements for a successful "roll out" (e.g.: strategy and training plan) are delineated in Section 5, Implementation Plan.

EXCLUSIONS FROM SCOPE

The project does not include:

- activities following completion of the inventory (e.g. corporate summations, public relations, release reduction strategies)
- release reduction strategies

EXCLUSIONS FROM SCOPE (CONT'D)

- data on storage of hazardous and high profile chemicals
- tracking of onsite reduction, reuse and recycling (inadequately defined at this time)
- tracking and/or reporting EXTERNALLY other than for NPRI / NERM and corporate summaries
- data on purchased materials (supplier, composition, end use, quantity used, quantity released)
- accurate quantification of substance use
- products of combustion of transportation fuels
- releases from facilities that IOL does not operate.

RATIONALE

The project organization reflects both the decision to take a corporate approach and the multiple stakeholders within IOL for release inventory information.

PROJECT SPONSOR

The IOL Environmental Health and Safety Committee is sponsoring the project, providing overall direction to the project team and approving recommendations and expenditures for the definition and design phases. Divisional representatives on this committee support communication with and related approvals by business managers within their respective organizations. Members of this committee and their roles are:

Lynn Schryer - Manager, IOL Environment and Safety Department, EH&S committee chairman
Bill Levy - Manager, IOC Environment, Health & Safety, IOC business contact
Ed Caldwell - Manager, IOP Safety and Environmental Affairs Department, IOP business contact and day-to-day BIPI project contact
Randy Ottenbreit - Manager, IOR Environment, Safety and Industrial Hygiene, IOR business contact

PROJECT TEAM

The project team is composed of representatives for each division, information systems resources from the CSD Occupational Health Division and technical resources from Sarnia Reseach Department. The team is responsible for:

- delivering project products consistent with the mandate and objectives for the project
- ensuring related government and industry participation and communication
- coordination with related activities in affiliate networks (e.g., ECC, ECI, ER&E, etc.).

The project team members and their roles are:

Project Leader - Peter Baltais, IOP, SEAD
IOL Representative - Neil Murray, E&S Dept, IOL
IOC Representative - Idrees Mahmud, IOC, SH&E

PROJECT TEAM (CONT'D)

IOP Representative - Tom Hewitt, SEAD
- Dave Mitges, Refinery Services
IOR Representative - Roger Gallant, ESIH
Technical Support - Don Hewson, Sarnia Research Dept.
- Dennis Stirling, Sarnia Research Dept.
Information Systems - Jim Laughlin, CSD-OHD
- Lorri Thompson, CSD-OHD

IMPLEMENTATION NETWORK

An implementation network composed of the project team members for each operating division and their respective business unit/site BIPI coordinators is responsible for:

- o input of business and technical requirements to the definition and design phases of the project, and
- o leading the implementation within their respective organizations/sites. Members of this network include:

IOC Division operations - Idrees Mahmud
IOP, Dartmouth Refinery - Gilles Morel
IOP, Sarnia Refinery - Doug Scheer
IOP, Nanticoke Refinery - Kal Virk
IOP, Strathcona Refinery - Andy Teal
IOP, Ioco Refinery - Mich Charette
IOP, Distribution - Jim Whitlaw
IOR Division operations - Roger Gallant

DRIVERS

The major drivers influencing project timing and completion of release inventory data collection include:

- o the regulatory requirement under Environment Canada's NPRI initiative for reporting 1993 releases by June 1, 1994
- o IOL management's commitment to report corporate level release information to Exxon management in Q1, 1994
- o IOC Division's business requirements under CPPA's NERM initiative to report release information in May, 1994.

PROJECT MILESTONES

The significant milestones for the project based on these timing drivers are as follows:

February, 1993	- Definition Phase products complete - Recommendations reviewed with BIPI implementation network - Recommendations reviewed with EH&S Committee - Divisional management reviews underway
March, 1993	- IOL management committee review - Divisional approvals complete - Design Phase products complete
April, 1993	- Pilot implementation underway - Information system installation underway
May, 1993	- General implementation underway - Information system installation complete
June, 1993	- Progress reviewed and adjustments made as necessary
September, 1993	- Progress reviewed and adjustments made as necessary
December, 1993	- Progress reviewed and adjustments made as necessary
January, 1994	- Implementation complete - Release inventory summations underway - Communications plan underway

PROJECT MILESTONES (CONT'D)	March, 1994	- Release inventory summations complete - Communications plan reviews underway - Corporate summary reviewed with Exxon
	April, 1994	- Site NPRI reports generation underway - Communications plan reviews complete - IOC Division NERM report generated
	May, 1994	- Site NPRI reports generation complete - Communications plan implemented - Site BIPI turnover complete and ongoing maintenance mechanisms in place - Project team disbanded

SCHEDULE DETAILS

Detailed project schedule information is contained in Appendix IV of this document. It is expected that ongoing adjustments will made as implementation unfolds.

DELIVERABLES

The design phase will result in the creation or acquisition of tools based on the project definition. The tools will be generic to the company, with the exception of a refinery implementation guide being compiled by Products Division. The design phase will be completed by the end of March 1993.

Administrative procedures and release quantification methodologies will be documented in a BIPI manual.

An information system software will be acquired, implemented and prepared for use by the sites.

The project team will continue to operate through the design phase, providing divisional input to the products. The project leader will track progress on behalf of the IOL Environmental Health and Safety committee.

DESIGN APPROACH

Major elements of the design strategy include:

- a corporate approach to common definitions, methodologies and support systems
- minimized impact on sites
- responsibility remains with reporting facility
- assistance from respective central team members and information systems support during implementation
- maximum use of Exxon experience to expedite implementation
- maintain evergreen capability
- low cost, quick implementation
- use commercial computer software that is compatible with existing and planned IOL information systems tools.

INVENTORY OBJECTIVES

The objectives of the inventory parameters developed by the project team are to:

- use an optimized approach to compile a release database that will meet minimum regulatory, business and policy needs
- priortize on high volume, high sensitivity substances that will be reported publicly
- provide a basis for improving quality, as justified, over time with minimum throw away.

INVENTORY GUIDELINES

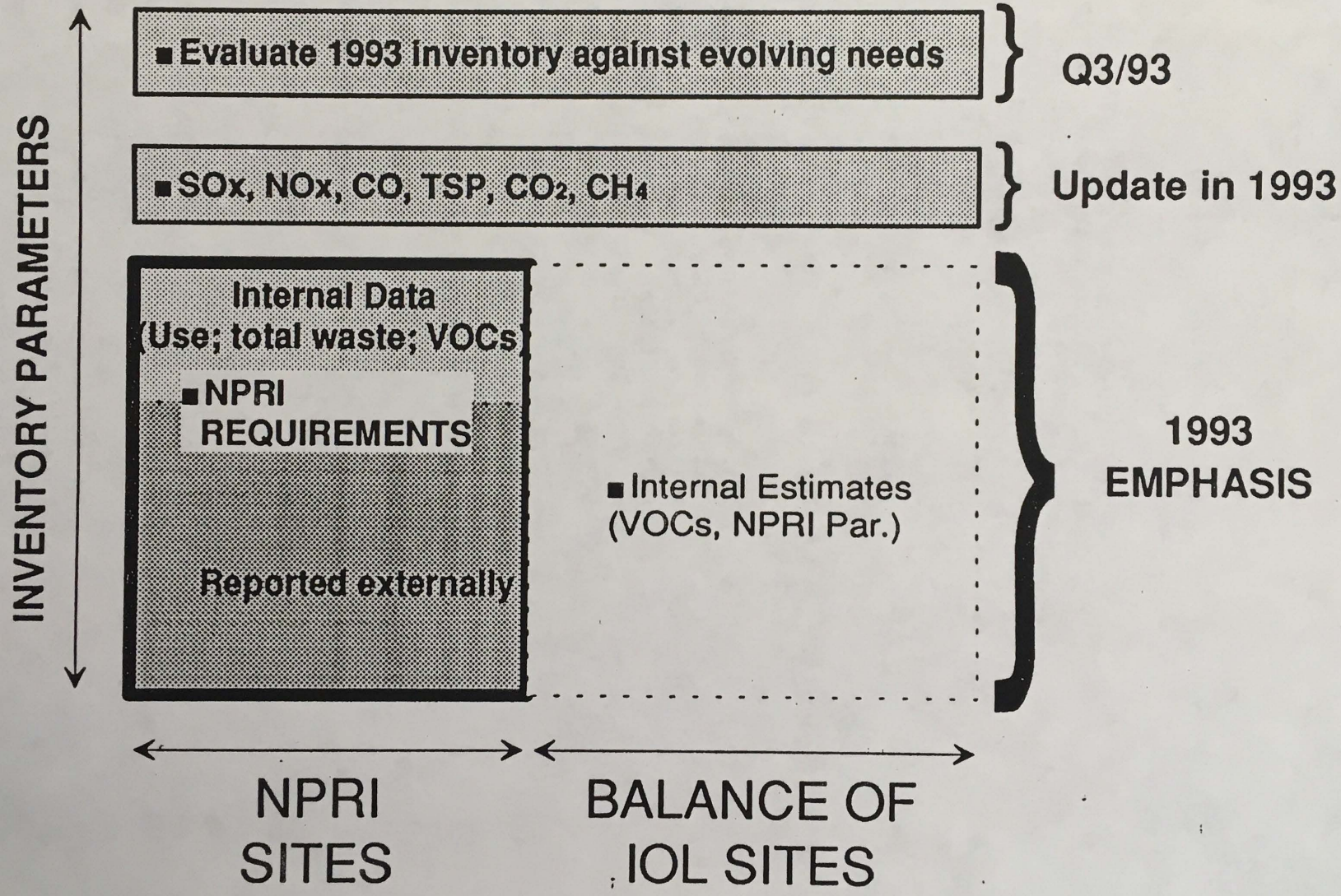
General guidelines applied to the inventory parameters include:

- Aim for a comprehensive database with major facilities reporting individually, while releases from small facilities are estimated as a group. Back-off where there is significant additional effort that is not warranted. The benefit is a comprehensive understanding with only small changes required for future reports.
- Meet NPRI and NERM requirements for reporting 1993 releases. Move towards US requirements (e.g. SARA), as appropriate. They are indicative of future Canadian requirements (see Appendix I, Inventory Parameters Detail).
- The 1993 BIPI standard should go beyond NPRI/NERM requirements if there is high value for the incremental effort required.
- Inventory scope and updates are based on regulatory and business needs.
- High profile substances are considered unique and are handled elsewhere.

1993 FOCUS

A phased approach is recommended (see figure, opposite). The emphasis in 1993 will be on compiling inventories to meet NPRI, and if applicable, NERM requirements for the facilities meeting NPRI/NERM reporting requirements. Only this data must be reported to NPRI.

SCOPE OF IOL RELEASE INVENTORY



INTERNAL UPDATE	The 1993 focus on NPRI (trace contaminants) and NERM will be complemented by an update of releases of conventional pollutants (SOx, NOx, CO and Total Suspended Particulate), climate change gases (CO2 and methane) and additional releases impacting ground level ozone (total Volatile Organic Carbons). The update is anticipated to require less than 10% additional effort over NPRI requirements and no additional effort over NERM requirements. This data would not be forwarded to Environment Canada with the NPRI data.
TOTAL WASTE TRACKING	Data on waste transfers is required to calculate the amount of chemical transferred off site. Total waste tracking systems are being installed and upgraded for major sites in 1993. Therefore, total waste (i.e. tonnes of contaminated soil vs grams of benzene in the contaminated soil) from major sites should be available for tracking in the 1994 release inventory. However, this detailed approach would be a burden on smaller sites at this time.
DOCUMENT AVAILABLE DATA	Divisions may elect to include sites not covered by NPRI or NERM (e.g. major, non-refinery terminal). Similarly, reporting sites are encouraged to include available data below reporting triggers and for substances not on the NPRI list, when the data is already available and easily added. This data would not be forwarded with the NPRI data.
REVISIT INVENTORY PARAMETERS	At the end of the 1993 roll out, the project leader, with input from the divisions, will evaluate the efforts and results of the 1993 release inventory against evolving needs.
PARTLY OWNED/ OPERATED SITES	In cases of sites where Imperial is not the sole owner or operator, Imperial will report total releases from sites for which it is the holder of the operating approval or is the operator. Therefore, even if Imperial holds less than 100% ownership, if it operates the site, Imperial will report 100% of the releases. Conversely, any site, for which Imperial holds a working interest but is not the operator or operator of record, will be excluded from the Imperial release inventory.

DOCUMENTATION

A Broad Imperial Pollutant Inventory Manual will be written. The Manual will consolidate the information obtained during the design phase. The information system may be documented separately.

CONTENT

The three major sections of the manual include:

- Release Inventory Basis and Management
  - Inventory Requirements
  - Inventory Scope
  - Definitions, Rules and Standards
  - Administration
- Quantifying Substances Manufactured, Processed or Otherwise Used
  - Methods
  - Data Collection
- Release Inventory Methods
  - Release Sources & Acceptable Release Methods
  - Data Collection

METHODS

Methods for collecting and quantifying release information will be evaluated and documented by project team members contracted from the Research Department. Appendix II provides additional information.

PRIORITIZED APPROACH

A prioritized approach is suggested for meeting NPRI/NERM requirements, as follows:

- identify facilities employing more than 20,000 hours per year work force and not exempt by NPRI
- identify NPRI-listed substances on site (i.e.: via request to the Employee Tracking and Health Information System helpdesk at (416) 968-4930)
- identify NPRI / NERM substances manufactured, produced or otherwise used in excess of 10 tonnes per year
- analyze available release data (e.g.: prior Exxon submissions) to estimate substances with largest releases from site, preferably also identifying potentially largest site sources
- identify "high profile" substances
- acquire higher quality data for large volume and "high profile" substances that will be reported externally.

DATA QUALITY

Both release inventory and substance use quantification should be calculated based on appropriate standards that meet regulatory, business and policy needs (see Appendix II, Methods).

SITE / BUSINESS UNIT

Communications with facilities compiling release inventories, or their management, has and will be done by the divisional teams. These groups will also design and communicate their activities to their employees.

CORPORATE /EXTERNAL

The Public Affairs group will be approached to coordinate Corporate and external communications.

I.S. OBJECTIVE

The goal of BIPI information systems support is to enable IOL divisions and the management company to meet related regulatory, policy and business needs in the most cost effective manner by:

- taking advantage of all existing information in IOL which supports BIPI development (e.g.: ETHIS site inventories, process data, laboratory data, etc.)
- acquiring a commercial software package that reduces the work effort required for collection, analyses and reporting of release information at site/business unit, divisional and corporate levels.

SOFTWARE EVALUATION

The key areas considered in evaluating commercially available software packages included:

- System - Functionality
  - Architecture
  - User Interface
  - Full integration of modules
  - Technical fit with IOL computing environment
- Security controls and data integrity
- Supplier viability and Canadian support capability.

REQUIREMENTS

The project team established and prioritized the business and functional requirements for evaluating software packages (see Appendix III). This work was assisted by and validated against the requirements developed by Exxon environmental specialists based on their experience with similar regulatory, policy and business needs.

TECHNICAL FIT

Information Systems technical specialists at both corporate and site levels were consulted to establish the current and planned systems environments for all IOL divsions. Commercially available software packages were evaluated on their fit with the technical standards identified in this process. In addition, software vendors were evaluated on their ability to meet IOL supplier standards established by the I.S. Department.

SOFTWARE SEARCH

More than 50 commercially available software packages were identified which purport to support some or all of the desired functionality. All but five were eliminated based on significant shortcomings found in initial screening. Three of the remaining five had been eliminated by an Exxon Chemicals project team after an in-depth screening and their documentation was sufficient to allow the IOL team to arrive at a similar conclusion. One of the remaining two, the only Canadian package, was eliminated due to limitations in functionality, data integration and technical fit.

RECOMMENDATION

The BIPI project team concurred with Exxon Chemical's decision that the software package with the closest overall match to requirements is Oracle's EIS (Environmental Information System). It is the only system built with a petrochemical focus (orginally built for Dow by Oracle and later licensed to Oracle for commercial development) and the supplier, Oracle Corporation, is well-established and capable of supporting a Canadian implementation. Although it was not part of the evaluation basis, consistency with ECC's approach provides significant business and cost advantages.

DESIGN PHASE

Design phase activities will be focussed on confirming the viability of the EIS recommendation and, if confirmed, proceeding with an IOL implementation. They include:

- detailed evaluation of the software by business contacts in each IOL division via online access to the ECC pilot implementation at the Baton Rouge Chemical Plant
- involvement of IOL I.S. contracting specialists with Oracle and the ECC project leader to develop an IOL licencing agreement under the terms of the existing Exxon agreement
- involvement of IOL I.S. operations specialists with their Oracle counterparts to further understand EIS hardware requirements and identify existing IOL hardware capable of running the data base
- completion of all reviews required by IOL systems and business controls standards (e.g.: CAPS, MCSCS).

REFINERY IMPLEMENTATION GUIDE

The Products Division team will complile an implementation guide focusing on refineries, with a section for terminals. The guide will be a cookbook, or "how to" manual to assist these facilities in planning their approach to the inventory. It will refer to the BIPI Manual for methodologies and standards.

The guide will have three major sections:

- Overall Approach to Refineries
  (site team structure, strategies, quantifying use, information sources,..)
- Approach to Refinery Units
  (for process units, storage, loading, waste handling,... including process blocking, source checklist and typical releases)
- Approach to Terminals

OVERALL TIMING

The objective is to have the inventory of 1993 releases virtually completed by/for sites at yearend 1993. This timing allows for corporate summations and analysis before NPRI (June 1) and NERM (May 31) submissions in 1994. Sites will require some time in early 1994 to incorporate operating conditions for December.

INDEPENDENT IMPLEMENTATION

The inventory will be compiled independently in each division. The two Chemicals sites will have completed a number of Exxon Chemical Waste and Waste Reduction Program inventories and at least one NERM inventory by mid-1993. The Products Division has a central team to support the sites, while Resources Division may choose to compile the inventory centrally.

Although the divisions will have the flexibility to implement based on their differing circumstances, they will be following the common standards and using the tools defined and designed by the corporate project team.

TRACKING DIVISION RESPONSES

Progress on the compilation of the inventory will be tracked by each division. Experiences will be exchanged through an informal network. In addition, progress will be tracked by the project leader and reported to the IOL Environmental Health and Safety committee.

SUPPORT DURING IMPLEMENTATION

First-contacts for support during the implementation phase, by function, include:

- use quantification: facility contacts (e.g. storehouse), alternatively the divisional inventory leader
- data collection and calculation methodologies: divisional inventory leader, Sarnia Research
- information system: corporate Occupational Health Division, systems support group
- approaches to inventory compilation: divisional inventory leaders
- BIPI Manual: corporate Environment & Safety Department
- regulatory developments and interpretations:
  NPRI - IOP - Safety and Environmental Affairs;
  NERM - IOC - Environmental Affairs

OVERALL TIMING

If, as expected, design phase activities do not identify any serious impediments to acquiring Oracle EIS to support BIPI rollout, the proposed timing for implementation is as follows:

- o complete all reviews and approvals by end Q1, 93
- o acquire and load software (V.2) on IOL hardware and complete all related operations and business testing by end Q2, 93
- o convert and load all existing site/business unit data that is currently available to support BIPI activities (e.g., ETHIS chemical master information, distribution data stored in PSIS software, process and lab data)
- o implement release calculations, analyses and reporting functions at BIPI sites starting in Q3, 93 and support site application training and data loads as necessary throughout implementation over 1993 and early 1994
- o support local, divisional and corporate reporting and summations as necessary over Q1 - Q2, 1994 to meet all regulatory and business target dates.

CONTINGENCY PLAN

In the event that serious impediments to Oracle EIS acquisition occur, the fallback alternative is to use the "patchwork" of PC-based softwares that have been developed by Exxon and regulatory agencies for release calculation, analyses and reporting. Although these are not integrated and will require significant additional work effort for multi-level consolidation of data, they have been used in Exxon for several years and provide a feasible contigency backup for meeting regulatory requirements in 1994.

WORKPLAN

A detailed informtion systems workplan is provided in Appendix IV. The following summarizes the key activities and resource requirements.

Activity	OHD	I.S.	Timing
Prelimary CAPS & Technical Reviews	.5	.5	Q1, 93
Vendor Contract Negotiation	.2	.3	Q2, 93
Software Installation & Testing	1.0	.5	Q2, 93
Security Environment Established	.3	.2	Q2, 93
System & User Documentation	1.5		Q2, 93

WORKPLAN (CONT'D)

Activity	OHD	I.S.	Timing
Compile & Load Existing Data	1.0		Q2, 93
Load Pilot Site Data (Nanticoke)	.5		Q3, 93
Implement at Remaining Sites	2.0		Q3, 93
Load Site Inventory Data	4.0		Q4, 93
Produce 1993 Reports	1.0		Q1, 94
Migrate to Version 3.0	.5	.5	TBD
Total Workmonths	12.0	2.0	

CENTRAL SUPPORT

The existing information systems support capability within the Occupational Health Division will be extended to include ongoing EIS support, likely with no additional resourcing. This capability includes:

- security administration, application training and helpline (currently provided to 400 ETHIS users in all IOL divsions and locations)
- data management support, including high volume keying and data loads and maintenance of interfaces with other applications providing information to support EIS functions
- system management mechanisms, including an existing arrangement with the IOL EH&S committee to provide input to and steward costs/activities and established networks with distributed site users and systems professionals
- cost distribution mechanisms, including established EH&S buyers/IME process and an internal tracking system to maintain records of work performed by division and site/business unit.

Ongoing application development and support will be done by the vendor through planned releases which incorporate IOL requirements. No inhouse programming (other than to maintain data interfaces) will be done. This will ensure that IOL continues to be positioned to take advantage of all vendor upgrades.

RELEASE MANAGEMENT

As upgrades to the existing functionality become available (e.g., Version 3.0 to be released in Q4, 1993), OHD will work with the vendor, I.S. operations/site personnel and site users to manage installation, testing and migration.

APPROACH

Facilites are responsible for compiling their inventories as well as for the quality and accuracy of the data provided.

Products Division will focus on releases from refineries. They are required to report to NPRI, the sources are complex and they are the largest contributor to releases by the division.

Quantification of releases from Distribution and Marketing are important for completing an internal understanding of total releases by Products Division. Cost effective techniques that provide rough estimates are proposed.

STRATEGY

The regulatory basis for compiling the release inventory is that only information in the possession of the respondent, or information that they may reasonably expected to obtain, need be submitted. Therefore, new analysis would only be done to fill significant data gaps, such as streams with high volumes of sensitive chemicals.

FACILITIES & PARAMETERS

Based on the recommendation of the multi-stakeholder advisory committee, the National Pollutant Release Inventory will include all IOL refineries, but exempt the following facilities from reporting to the NPRI:

- facilities associated with the distibution or retail sale of fuels (e.g., service and pumping stations)
- research and testing laboratories (review exemption in 1994).

REFINERY OPERATIONS

The NPRI is modeled after the U.S. Toxic Release Inventory (TRI). Based on the U.S. example, Sarnia site is defined as a single facility. Although the chemical plant, refinery and research facility (if and when it is included) may report separately, reporting triggers will be based on the use of substance across all three facilities.

U.S. experience also suggests that refinery release inventories will include associated distribution terminals and tank farms.

REFINERY OPERATIONS (CONT'D)

The project team recommends that refinery reports include terminals, the loading of ships and adjacent pipeline pumping stations. Emission during marine loading are significant (half of the release from some US refineries) and yet are relatively simple to estimate. Although pumping stations are not anticipated to be significant sources, the small additional effort by a refinery team will provide a basis to project releases at stations nationally.

Products Division management will need to decide if emissions from marine loading will be reported externally (i.e. to NPRI). U.S. refineries recommend marine loading emissions be included as a major source because a step increase in future refinery emissions, due to the addition of marine loading, would not be well received. On the other hand, it is virtually impossible for loaders to control releases from marine vessels due to the variety of fittings, ownership of the vessel and international laws.

Refineries are tracking total wastes (i.e. tonnes of contaminated soil versus grams of benzene in soil). This information should be added to the release inventory because 1) contaminated soil, cardboard, building materials... are pollutants, and 2) total waste volumes are required in order to quantify the hazardous substances in the waste.

LABORATORIES

Inspection labs are specifically included with facilities in the U.S. The NPRI can be interpreted to exempt these facilities in Canada. A comprehensive inventory requires some estimate of releases from inspection and research labs. However, laboratories handle many substances in small volumes. The releases are thought to be relatively small and the effort to quantify them complex and burdensome.

Therefore, it is recommended that these facilities include in the 1993 inventory whatever information is available without analysis (e.g. past studies of vent compositions and waste tracking) and this position be reviewed at the conclusion of the initial inventory year.

Laboratory water effluents and wastes are tracked as part of the associated refinery.

DISTRIBUTION FACILITIES

Facilities involved with the distribution or retail sale of fuel are anticipated to be exempt from reporting to the NPRI. Environment Canada will calculate releases from these facilities for inclusion in their report to the public.

In 1992, Environment Ontario requested release data for selected terminals operation in Ontario (e.g., Finch). They have indicated they will continue to seek this information. There is also a trend for future operating permits to have fees based on releases from the site.

Emissions from terminals comprise about 10% of all IOP emissions to air, based on a 1988 CPPI survey of emissions from the downstream petroleum industry. Therefore, although not legally required, Distribution should have an understanding of "NPRI" releases from terminals so that releases may be assessed and managed appropriately. Distribution would also be in a better position to respond to numbers compiled and published by Environment Canada or other government agencies (e.g., Ontario).

Distribution should evaluate cost effective approaches to estimating releases from the terminal network. They could make use of the proposed information system, assistance from Research and/or data submitted to CPPI in 1988.

PIPELINES

The project has not included the estimation of releases from pipeline pumping stations. These releases are felt to be insignificant compared to releases from refineries, distribution and marketing.

MARKETING FACILITIES

Facilities involved with the distribution and retail sale of fuel are anticipated to be exempt from reporting to NPRI. Environment Canada will calculate releases from these facilities for inclusion in their report to the public.

Emissions from marketing comprise about 40% of IOP emissions to air based on a 1988 CPPI survey of emissions from the downstream petroleum industry. Therefore, although not legally required, IOP should have an understanding of "NPRI" releases from marketing. This data would allow marketing, IOP and IOL to have a first pass understanding of hazardous releases from their sites, so that they may be assessed and managed appropriately. They would also be positioned to respond to the numbers published by Environment Canada.

MARKETING FACILITIES (CONT'D)

Marketing should evaluate reasonable, low cost approaches. They could use the CPPI methodolgy for compiling 1988 hydrocarbon release inventories (i.e., average annual throughputs and standard configurations) to estimate national emissions of NPRI substances. There are about 900 company and agency operated service stations of various sizes and about 800 bulk plants (agency operated; salary operated; satellites; aviation agents and salaried; marine agents).

PROJECT MANAGEMENT SUPPORT

A central Products project team will support the design and initial stages of implementation. They will coordinate and steward the IOP response, ensuring consistent data quality and comprehensiveness across the division and the company. They will also provide a Refinery Implementation Guide, training and assistance focused on the refineries.

Technical support on analysis and estimation of releases will come from Sarnia Research with some support from the emissions estimating group at Exxon Research and Engineering.

The corporate Occupational Health Division will provide support of information systems.

Individual refineries will compile their own inventories with assistance from the project team.

Distribution and Marketing groups will compile their inventories with assistance from Sarnia Research.

Implementation plans will be outlined with milestones that map into quarterly progress checks, starting in June, 1993.

POST-PROJECT SUPPORT

Upon completion of the project, refineries will be able to compile and/or update future inventories. Distribution and Retail will have a basis to estimate future inventories themselves or with assistance.

Sarnia Research will continue to provide technical support for the analysis and estimation of releases.

The Occupational Health Division will continue to support information systems.

POST-PROJECT SUPPORT (CONT'D)

The IOP Safety and Environmental Affairs group will continue to support regulatory developments.

The central project group will be disbanded.

SCHEDULE

* CPPI NPRI workshop (January 26, 27)
* site response leaders meeting (January 28)
* design phase complete (March 31)
* approach to Information System confirmed (March 31)
* BIPI Manual (with methodologies) complete (March 31)
* Refinery Implementation Guide complete (March 31)
* training sessions at refineries (over Q2, 93)
* implementation plans mapped out at site level ; site leadership team understands the direction of senior management; site team in place with clear understanding of need, priority, roles and expectations (May)
* NPRI reportable substances identified (over Q2, 93)
* progress checks (June, September & December)
* release inventories virtually complete (December)
* release inventories complete (January)
* workshop to identify learnings for 1993 and prepare for 1994 (February, 1994)

TRAINING

All refineries will receive onsite training based on the BIPI manual, the Refinery Implementation Guide and the information management system. Training will be both classroom and in the field. The sessions will be facilitated by representatives from Refinery Services and Sarnia Research.

IMPLEMENTATION RESOURCING & COSTS

The major elements for calculating costs include:

- o central products team - 3 people for 1 year
- o Research team - 200 K$ for refineries
- o Refineries - average of 2 workyears effort per site
- o Distribution - minimum effort, Distribution 15 K$ support, Research
- o Marketing - minimum effort, Marketing 30 K$ support, Research
- o Printing/Reproduction - 10 K (project materials)
- o Travel Expense - 30 K

Total workmonths - 156
Total other expense - 40 K
Software Licence - 129 K

SCOPE

The IOR implementation plan is based on the inventory scope described in section 030 and includes:

- as a minimum, 1993 releases of NPRI listed substances
- a high want is to be able to report internally (e.g., Exxon) all conventional pollutant releases in 1993 from all operations by Q1 1994
- several high profile substances (PCB, Halon, CFCs) exist in IOR operations which have virtually no releases but which should be inventoried as to quantities in order to be capable of demonstrating proper management of these substances and measuring progress in phasing out or destroying them
- Operations Integrity and Alberta waste management regulations under development require waste tracking (i.e., quantification, classification, documenting disposition) of both common wastes and substances, some of which may be listed, and implementation during 1993 with consistent tracking beginning in 94 01 01 seems practical
- it is also desireable to complete the inventory of substances from all operations beyond what is reportable under NPRI and this will be reviewed late in 1993 after experience implementing the reportable sites is gained.

SUBSTANCE SOURCE MODEL

IOR operations process petroleum constituents rather than manufacture substances such as refining, and more so, chemicals operations. Upstream facilities separate mixtures of raw production stream molecules rather than manufacture new molecules from various feedstockes. This suggests different and possibly simpler approaches may be applicable in IOR compared to IOP and IOC.

IOR operates over 11,000 wells and 700 minor facilites, all of which will not be NPRI reportable sites (less than 20,000 workhours per year). Only a few sites are large enough to be potential NPRI reportable sites. Raw production from wells enters a variety of small field facilities or plants where it is processed completely into products or partially processed and transported to larger plants to be processed into products.

SUBSTANCES SOURCE MODEL (CONT'D)

Facilities are geographically divided into operating areas for management of the operations. An operating area will have a diversity of small and large sites, one or more operating offices and varying amounts of facility technical support.

Three sources contribute to the existence of listed substances in IOR operations:

1. Raw Production Streams. If a listed substance is not present naturally in production from oil and gas resevoirs, then it is not available to be released from sources in the facilities. Thus compositional analysis of raw (prior to introducing any chemicals) production is a starting point to quantify listed substances being processed at IOR sites.

2. Substances in Purchased Chemicals. Purchased chemicals and products are used at all sites for various reasons and represent a more likely source of listed substances. Chemicals introduced at small field facilities can move with production to large sites. Because of this an the way purchasing functions are organized, it is sensible to look at this source on a broader basis, probably an entire operatiog area, thus covering both NPRI and non-NPRI sites.

3. Substances Produced. IOR operations will not likely produce NPRI listed substances. If not present naturally (i.e., raw production) any substances produced are unintentional byproducts and likely not present in significant quantities. Other listed substances, conventional pollutants such as CO2, NOx, SO2, and CO, are produced in significant quantities from combustion reactions.

POTENTIAL NPRI SITES

About 12 - 15 IOR sites employ the equivalent of 20,000 workhours per year, thus meeting the first NPRI reporting trigger. These are the larger oil, gas and bitumen processing plants. The list has not been confirmed by determining actual workhours. The opportunity to combine several separate but interconnected and geographically close sites into one reporting site should be examined. The following table lists potential NPRI sites.

POTENTIAL NPRI SITES (CONT'D)

	Operating Area	Site
Northern Division	Norman Wells	NW CPF / Refinery
	Judy Creek	JC Gas Plants
		JC Fieldgate
		Swan Hills 3 - 18
	Grande Prairie	Wapiti Gas Plant
		Boundary Lake Gas Plant
Southern Division	Battle River	Bonnie Glen Gas Plant
		Leduc Gas Plant
		Golden Spike Gas Plant
	Quirk Creek	Quirk Creek Gas Plant
Property Rationalization	Decentralized Operations	Redwater Gas Plant (Includes fieldgate)
Oil Sands	Cold Lake	Maskwa
		Mahikan
		Amisk
		Pilots

WORK STAGES

Based on the inventory scope, the effort is divided into several steps. Only the base case is non-discretionary under NPRI requirements. The remaining components of the scope are discretionary with the possible exception of waste tracking required to meet OI and emerging regulatory requirerments. All incremental effort beyond the manadatory needs will require justification on the basis of potential business and environmental benefits. Compared to the Base Case:

- o determining non-reportable NPRI substance releases at NPRI sites will be a medium effort (about 50% of the Base Case effort) assuming there is no attempt to detect and quantify NPRI listed substances unintentionally produced somewhere in the process (i.e., source type 3).
- o determining non-reportable releases from non-NPRI sites will a medium effort, provided lower quality estimates for type 1 and 2 are intended and no search for type 3 substances is undertaken
- o determining conventional polluntant releases at all sites for 1993 is a low-medium effort which will be approached by doing an update of the 1989 Greenhouse Gas Inventory to account for divestments, better emmisions

WORK STAGES (CONT'D)

factors/methodologies (CPA VOC Emissions Study, 1991) and significantly changed production/fuel volumes. SO2 releases are currently reported to the government, with the exception of miscellaneous field flaring of sour gas.

- o determining inventories of high profile substances should require a relatively low effort since this data exists in each operating area and, if the planned information system for waste tracking provides a means of tracking them, the effort will largely for populating the database

- o implementing a waste tracking system will require a relatively high effort, particularly if the planned information system does not offer this functionality (the work months for this plan do not include the effort required to develop a stand alone system)

PROPOSED APPROACH

In summary, the recommended scope of work and approach for IOR is as follows:

1. Confirm which sites are NPRI sites (20,000 workhours or more per year)

2. Conduct detailed compositional analysis of the raw production that enters the NPRI sites to determine the presence of NPRI listed substances. To a large degree these analyses will also be of the production that enters non-NPRI sites or could be deemed representative of production elsewhere at other non-NPRI sites. Maximun use of existing compositional data will be made when adequate. The investment in the analyses will take much guesswork out of the effort and provide the basis for estimating non-reportable releases at NPRI sites and many non-NPRI sites.

3. For substances in purchased chemicals and products used, a broad look at all chemical purchases on a divisional or operating area basis will cast a net over both NPRI and non-NPRI sites. A starting point is to use ETHIS inventories to determine where substances exist and purchasing information to quantify substances usage. A preliminary inquiry indicated that "hard" purchasing data is generally not available. However, data sufficient to screen for NPRI substance usage triggers

PROPOSED APPROACH (CONT'D)

is likely available as "knowledge" within local materials units at operating sites or from other operations personnel. Vendors are another source of this data. This broader screening is necessary to determine direct usage at an NPRI site and indirect usage resulting from non-NPRI sites flowing to NPRI sites with production. The basis to determine usage at non-NPRI sites also results from this approach.

While the preceeding steps will provide much of the information needed to start determining releases from non-NPRI sites, clearly the 1993 work effort will be to establish releases from NPRI sites. Completion of non-NPRI sites, if later felt to be warranted on the basis of 1993 findings, would be deferred to 1994 or later.

4. The model built to estimate greenhouse gas emissions for 1989 will be updated to reflect significant changes in operations and any better assumptions that now exist.

5. The planned pollution release information system is assumed to have the functionality to include SO2 and high profile substances. As such, data that already exists in operations can be documented and compiled by the system.

6. A waste tracking system will be defined for IOR as a standalone proposal to meet regulatory needs, assuming that the planned pollutant information system does not have this functionality. As a minimum, comparable definitions, classifications, etc. should be in use across all IOL divisions, since this type of data is what other Exxon affiliates are developing to report to the Exxon EHS network.

It is expected that ESIH will lead and provide overall direction for the preceding steps. Nor NPRI substance releases a more central approach, at least initially, is preferred over training each operating area or site. The primary reason is that the extent of the effort, driven by the amount of listed substances being processed or used, is quite uncertain at this time. It may turn out that complying with NPRI requirements will need little effort because of the NPRI triggers and definitions.

A pilot approach to steps 2 and 3 is prosposed. After confirming which sites are NPRI sites, a pilot site and

PROPOSED APPROACH (CONT'D)

the associated operating area will be chosen. Since most NPRI sites will involve conventional oil operations (vs. Cold Lake), a conventional site and operating area are the preferred candidates. The pilot will be completed by mid-1993 with learnings from the pilot extended to defining the best implementation approach to the remaining NPRI sites over the balance of 1993 and early 1994. While the base release reporting year will be 1993, it doesn't seem critical at this time that release estimates be based on actual 1993 data, other than actual production volumes processed by a site. The pilot team would be comprised of Technical Services (ESIH, the appropriate Engineering Services facility technical support), representatives from operations (Environmental Advisor, plant technical, local materials purchasing) and Materials & Contracting.

Step 4 will largely be completed by Technical Services (e.g., Engineering Services) with support from each operating area as necessary.

Step 5 will be completed by each operating area assuming availability of a system to support the data compilation.

Step 6 needs more development of the scope before proposing an approach.

EXPECTED STATUS YEAREND 1993

Based on the preceding, IOR should be capable of reporting the following in the first half of 1994:

1. Complete and accurate NPRI substance releases from NPRI sites

2. Complete and accurate inventories of high profile substances and releases of SO2

3. Reasonably accurate releases of conventional pollutants.

Incomplete information for non-reportable NPRI substance releases will be available. Capability to comment on the potential environmental significance of any releases, particularly at NPRI sites, should exist due to the approach proposed. Developing a more accurate view, if necessary, is not proposed for 1993. No data will be developed on waste generation and disposition nor on source type 3 NPRI substances.

PROJECT SCHEDULE & RESOURCES

A detailed work breakdown, task list and schedule and the preliminary resource requirements to complete the proposed scope is provided in Appendix 0. The resource table was constructed assuming all work stages were completed at once. This was done in order to attempt an estimate of the incremental work effort for each stage relative to the base case. The table shows the estimated effort broken out for all stages and is very preliminary.

The following is a summary of the resource requirements and schedule by project phase.

Phase		W/M	Completion
Base	Reportable NPRI Releases	17.0	Q1, 1994
1	Non-reportable NPRI Releases (NPRI sites only)	8.0	Q1, 1994 (incomplete)
2	Non-reportable NPRI Releases (all other sites)	5.8	Q1, 1994 (incomplete)
3	Conventional Pollutants (all sites)	2.6	Q1, 1994
4	High Profile Substances Inventory	0.9	Q1, 1994
5	Waste Tracking	2.6	TBD
	Total Work Months Effort	38.6	
	Proposed Work Months Effort	28.0	

The following is a summary of the resource requirements by resource type and project phase.

Phase		ESIH	TECH SERV	OPNS	OTHR
Base	Reportable NPRI Releases	3.6	5.2	6.2	2.0
1	Non-reportable NPRI Releases (NPRI sites only)	0.9	4.3	2.1	0.8
2	Non-reportable NPRI Releases (all other sites)	0.7	2.1	2.6	0.6
3	Conventional Pollutants (all sites)	0.7	0.6	1.3	
4	High Profile Substances Inventory	0.1		0.8	
5	Waste Tracking	1.3	0.3	1.0	
	Total Work Months Effort	7.2	12.5	13.8	3.5
	Proposed Work Months Effort	5.2	10.1	10.7	2.0

BACKGROUND

For Chemicals Division, compliance with NPRI requirements and the other elements of the proposed BIPI scope can be accomplished with a relatively small effort since much of the data is already being collected to meet existing commitments to ECC's waste reduction program and CPPA's NERM. The incremental effort will be directed primarily towards additional speciation of streams and implementation of the recommended information system.

ESTIMATE

The estimated incremental effort is 3-6 workmonths for each of the two IOC locations required to report under NPRI.

EXXON EXPERIENCE

U.S. environmental regulatory reporting requirements have grown exponentially over the past 20 years. As a result, site organizations that perform and support environmental record keeping and reporting have grown dramatically, partly due to the independent development of programs and related information systems by multiple sites and business units. These fragmented and site-specific programs have been costly to develop and maintain, both in direct and indirect costs for environmental and I.S. resources. A study conducted in 1992 by Exxon Chemical reported the following consequences of this fragmented approach:

- the growth rate of environmental resource is 50% greater than at Dow, where an integrated approach was initiated in 1987
- direct costs for information systems are currently at 2M$ (US) annually and growing, as individual sites add applications that need to be maintained or license different third party softwares (Note: indirect costs for development of spreadsheet and other applications by environmental professionals was not quantified but is considered significant.)
- much of the data that supports ECC's environmental compliance activities are stored in insecure environments (e.g.: handwritten notes, unprotected PC databases, flat files, Lotus spreadsheets, etc.), are are incumbent-dependent (i.e.: prone to loss with changes in staffing) and may not meet regulatory audit trail standards
- non-integration greatly complicates the process of compiling regional and company-wide reports due to incompatible definitions, formats, applications, etc. and results in significantly increased effort for this activity
- incorrect responses by individual sites confused about the exact reporting requirements has resulted in fines.

The study concluded that a comprehensive, company-wide program to address current and future needs was required and made the following recommendations:

- develop a management system to coordinate, integrate and focus emerging needs, and

EXXON EXPERIENCE (CONT'D)

- identify and implement a commercial integrative software package to support it.

Although studies like ECC's have not been done in other parts of the affiliate network, discussions with environmental professionals from EUSA and ER&E indicate that non-integrative approaches elsewhere in the organization have resulted in similar issues and redundant costs (see Appendix V). Advice to the project team provided by these sources included:

- doing it right the first time will result in reduced resource requirements of up to 50 percent for subsequent reporting years and lowered risk of gross understatement of baseline emmissions (ineffective startup processes in the U.S. has resulted in upward revisions of baselines emissions annually by up to an accumulated change of 100 percent)
- an integrated information systems approach is the key to achieving efficiencies
- design a program that anticipates future requirements up front to avoid costly rework.

COST/BENEFIT BASIS

A major driving force for the BIPI project is to capture the opportunities for containing costs and minimizing related issues by taking a common approach within IOL for developing a release inventory. Although the scope of the project does not include all the regulatory, policy and business needs encompassed by the scope of ECC's study (i.e.: an "environmental management system"), the Exxon experience in implementing a Toxic Release Inventory (TRI) on which the Canadian NPRI regulation is based forms a large part of the requirements which contributed to the result documented in their study. We believe, therefore, that it is a valid model for developing the cost/benefit analysis for the BIPI project.

COST ESTIMATE ASSUMPTIONS

The following assumptions form the basis for estimating the total costs for the project:

- labour average cost is assumed to be 10K per work month with the exception of contracted services (e.g.: ER&E, Sarnia Research Department, I.S. operations personnel) where the specified contract cost is used
- average site labour required to implement a refining operation is 2 work years and 5 refinery sites will be done with assistance from a central IOP team and Sarnia Research Department
- average site labour for upgrading existing chemical operations data to meet NPRI requirements is 6 months per facility and 2 facilities will be done
- total labour for estimating/upgrading data for retail and distribution operations is 3 work months, including 5 weeks of support from Sarnia Research Department
- total labour to identify and inventory upstream operations NPRI releases, SO2 releases, high profile substances and conventional pollutants is 28 workmonths.
- training for site implementation teams will occur onsite and will not involve significant travel costs for site personnel
- no new hardware costs or database license fees are introduced by this project and application software costs for the recommended solution are estimated at 258K for license fees and 25K for acquisition process and installation by the IOL I.S. Department
- application licence costs will be borne by the I.S. Department who will determine appropriate user charges to recover this cost from each division on an ongoing usage basis.

Facility implementation assumptions were derived from Exxon affiliate experiences in submitting data to the U.S. Toxic Release Index. A major source of uncertainty is the fact that U.S. facilities had LDAR (leak detection and repair) programs in place at startup while IOL facilities do not.

TOTAL PROJECT COST ESTIMATE

The following details total project workmonths and costs by division. Analyses by project phase and products are provided subsequently.

	Total		IOC		IOP		IOR	
	W/M	K$	W/M	K$	W/M	K$	W/M	K$
DEFINITION/DESIGN PHASES								
Central Project Team	11	124	0.5	6	10.0	105	0.5	13
Information Systems	6	63	1.2	13	3.0	31	1.8	19
Sarnia Research Dept	5	110	1.7	36	1.7	37	1.7	37
Total	22	297	3.4	55	14.7	173	4.0	69
IMPLEMENTATION PHASE								
Central Project Team	23	278	0.5	7	22.0	261	0.5	10
Information Systems	12	140	2.5	28	6.2	70	3.7	42
Sarnia Research Dept					12.0	220		
Site Implementation Teams	136	1373	6.0	67	101.5	1015	28.0	291
Total	205	2011	9.0	102	141.7	1566	32.2	343
SOFTWARE LICENSE		258		52		129		77
TOTAL PROJECT	205	2566	12	209	156	1868	36	489

All resource is assumed to be reallocated from existing pool. I.S. costs are already sponsored in 1993 division budgets via the Occupational Health Division IME process. The only new external cost is for a software license which will be borne by the I.S. Department and recovered via a chargeout formula to be negotiated. Estimate is based on projected number of implementation sites by division.

DEFINITION PHASE PRODUCT COSTS

The following details costs by product for the definition phase.

PRODUCT	W/M	K$
Inventory Framework & Parameters	2.0	27.0
IOL Definitions, Guidelines & Methodologies	6.6	108.0
Information Support Strategy (Existing Data)	.5	6.0
Information System Requirements, Alternatives & Recommendation	3.0	34.0
Divisional Implementation Plans	2.5	25.5
Project Cost/Benefit Analyses & Documentation	1.5	14.5
Totals	16.0	215.0

DESIGN PHASE PRODUCT COSTS

The following details costs by product for the design phase.

PRODUCT	W/M	K$
Generic Procedures & Methodologies Documentation (BIPI Manual)	2.7	48
Information System Validation & Purchase	1.6	17
Refinery Implementation Guide (IOP)	1.7	17
Totals	6.0	82

IMPLEMENTATION PHASE PRODUCT COSTS

The following details costs by product and division for the implementation phase.

PRODUCT	W/M	K$
Division Implementation Capability, Support & Stewardship (Project Team)	22.5	263
Software Installation & Site Data Loads	11.8	134
IOC Site/Business Unit Implementation	6.0	67
IOP Site/Business Unit Implementation	112.5	1235
IOR Site/Business Unit Implementation	28.0	291
Internal/External Communication Strategy	2.4	26
Totals	183.2	2011

SOFTWARE COSTS

The Oracle EIS software will be acquired under an existing Exxon agreement which allows affiliates to license it for a onetime cost of 12.5 K$(US) per concurrent user, with a minimum of 16 concurrent users licensed. Under this arrangement, any number of IOL employees may be given access privileges but only 16 can be logged on at the same time. The project cost was estimated based on the minimum number of concurrent users and an exchange rate of 1.29. Annual maintenance fees are charged at 15% of licensing fees and any IOL-specific enhancements will be billed at 50% of Oracle's usual consultant billing rates.

INTRODUCTION

Project benefits for this non-discretionary activity are derived from two areas:

- o reduced costs related to taking an integrated corporate approach for implementing release inventories
- o cost savings related to the availability of a comprehensive IOL inventory of releases for ongoing management and response purposes

REDUCED STARTUP COSTS

The Exxon experience in this area and other past examples within IOL have demonstrated that allowing each division, business unit or site to mount an independent response results in duplication of costs and proliferation of response systems. The degree of waste is usually directly related to the number of independent responses. If we apply the Exxon experience to the IOL organization, we can assume that 8 independent responses would have been made. Applying that assumption to BIPI definition and design costs results in the following calculations:

o cost of determining inventory parameters, definitions & methodologies and developing training & implementation tools = 8 X 3 W/M	240 K
o cost of determining information strategy & requirements, identifying or developing I.S. tools and implementing them = 8 X 5 W/M	400 K
o adjustment for BIPI project costs	(500)K
Net Benefit	140 K

REDUCED MAINTENANCE COSTS

Annual maintenance costs include adjustments to parameters, methodologies and related documentation as well as ongoing support of information systems tools as regulatory and business needs evolve. Applying the same assumptions to this activity results in the following calculations:

o annual maintenance of current parameters, methodologies & documentation = 8 X 1 W/M	80
o annual I.S. maintenance and support = 8 X 5 W/M	400

REDUCED MAINTENANCE COSTS (CONT'D)	o adjustment for central maintenance of BIPI tools, 15% Oracle EIS maintenance, central software support costs (helpline, security access, data management, etc.) and user fees	(150)K
	Net Benefit	330 K

REDUCED ANALYSES & REPORTING COSTS

The requirement for multi-level analyses and reporting of release data provides another area of benefit for taking a common approach to definitions, parameters, methodologies and information systems. Again, the Exxon experience and other IOL examples (e.g.: Loss Control reporting) provides the basis for the following calculation:

o annual cost of site/business area release reporting alignments at divisional and corporate levels = 4 X 1 W/M @ 12.5 K	50 K

RELEASE MANAGEMENT & RESPONSE

U.S. experience and studies indicate that ongoing costs for regulatory and other reporting can be reduced by up to 50 percent with an integrated and focussed initial effort and the use of sophisticated information systems technology. Another source of savings is related to the availability of comprehensive release data for response to new regulatory, policy and community information requirements with little incremental effort. A conservative estimate of the benefit for these areas is 25 percent of the initial cost for collecting release inventories or 500 K$.

BENEFITS SUMMARY

Reduced one-time costs for NPRI/other regulatory and policy compliance achieved by taking a common appoach within IOL, including IS costs	140 K
Annual maintenance and support costs savings of shared methodologies, computer and training tools	480 K
Annual communications analyses/alignment cost savings of implementing consistent reporting basis and shared database for all IOL divisions	50 K
Annual cost saving for improved release management and regulatory/community response capability for new requirements and issues	500 K

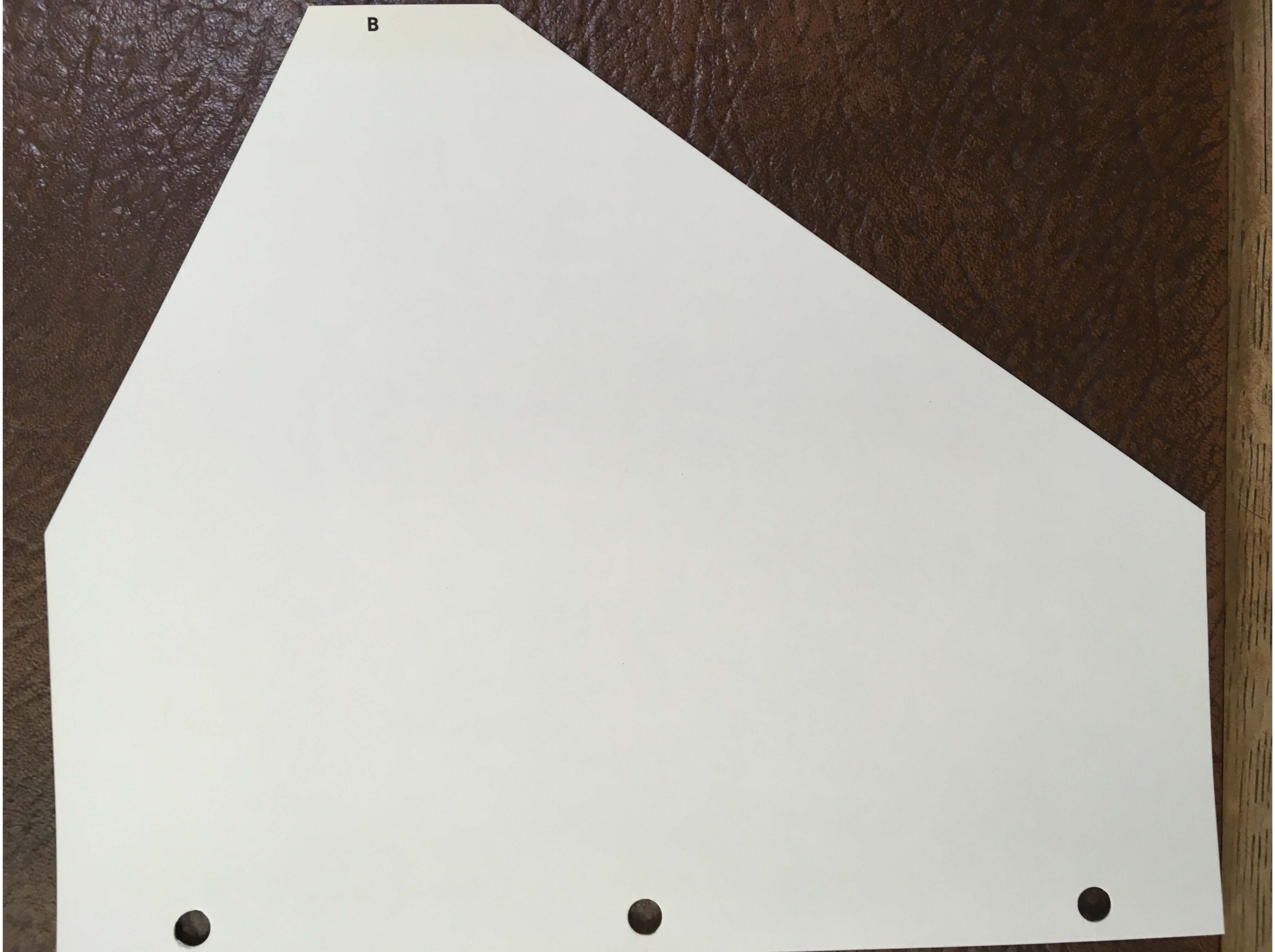
BENEFIT SUMMARY (CONT'D)

Ongoing central maintenance, support and database useage costs	(150)K
Ongoing site inventory maintenance/reporting cost	(500)K
Net benefit	520 K

QUALITATIVE BENEFITS

The qualitative benefits identified by the ECC study and other U.S. environment specialists for taking an integrated corporate approach include:

- improved overall quality of IOL's pollutant inventory information resulting from consistently applied standards, defintions, methodologies and parameters
- improved continuity and security over the environment for storing proprietary IOL data and better audit trails and documentation of the assumptions on which the inventory is based
- better alignment with affiliate network reporting in this area as result of shared information systems that enforce consistent data, formats and calculations (i.e.: In addition to the ECC project, Oracle EIS is under consideration by European and other U.S. affiliates and may become the worldwide Exxon standard)
- improved ability to compare results internally and develop benchmarks for IOL environmental releases performance
- improved consistency of internal and external communications and reduced risk of unfavourable trending related to initial understatement of release data in this highly sensitive public policy area.


B

APPENDIX 7: TABLE OF RECOMMENDED NPRI DATA ELEMENTS TO BE REPORTED

PART A: FACILITY IDENTIFICATION

1.0 Company name

2.0 Facility identification and address
- 2.1 Facility name
- 2.2 Street address
- 2.3 City
- 2.4 Lot number
- 2.5 Concession number
- 2.6 Township
- 2.7 Country
- 2.8 Province
- 2.9 Postal code

3.0 Facility contact
- 3.1 Name
- 3.2 Position
- 3.3 Telephone number
- 3.4 Facsimile number

4.0 Number of employees at the facility

5.0 Mailing address (if different from above)
- 5.1 Street address
- 5.2 P.O. box number
- 5.3 City
- 5.4 Province
- 5.5 Postal code

6.0 Facility location
- 6.1 Latitude: degrees, minutes, seconds
- 6.2 Longitude: degrees, minutes, seconds

7.0 SIC codes (Enter Canadian or U.S)
- 7.1 Canadian SIC code(s)
- 7.2 US SIC code(s)

8.0 Residual Discharge Information System Number

9.0 Domestic Substances List Number

10.0 Provincial operating permit number (if required by province)

11.0 Parent company information
- 11.1 Name of parent company
- 11.2 Street address
- 11.3 Box number
- 11.4 City
- 11.5 Province
- 11.6 Postal code

12.0 Approval for release to Environment Canada
- 12.1 Executive contact name
- 12.2 Position
- 12.3 Signature
- 12.4 Date

PART B: SUBSTANCE-SPECIFIC RELEASE INFORMATION

1.0 Substance identity
- 1.1 Chemical Abstracts Service Registry Number
- 1.2 Substance or substance category

2.0 Utilisation of the substance at the facility
- 2.1 Manufacture the substance:
  - a) Produce
  - b) Import

  If produce or import:
  - c) For on-site use/processing
  - d) For sale/distribution
  - e) As a byproduct
  - f) As an impurity
- 2.2 Process the substance:
  - a) As a reactant
  - b) As a formulation component
  - c) As an article component
  - d) Repackaging only
- 2.3 Otherwise use the substance:
  - a) As a chemical processing aid
  - b) As a manufacturing aid
  - c) Ancillary or other use

3.0 On-site releases of the substance to the environment

Report the basis of estimate code and the releases in tonnes for the following:
- 3.1 Air releases
  - 3.1.1 Stack/point
  - 3.1.2 Substance storage/handling
  - 3.1.3 Fugitive
  - 3.1.4 Spills
  - 3.1.5 Other non-point
- 3.2 Underground injection
- 3.3 Releases to surface waters
  - 3.3.1 Direct discharges
  - 3.3.2 Spills
  - 3.3.3 Leaks
  - 3.3.4 Receiving streams and water bodies codes from item 7
- 3.4 Releases to land
  - 3.4.1 Landfill
  - 3.4.2 Landfarm
  - 3.4.3 Spills
  - 3.4.4 Leaks
  - 3.4.5 Other

3.5 Total releases
3.6 Seasonal breakdown of releases by percentage in each quarter (To be completed if, in a quarter, releases amount to less than 15% or greater than 35% of of the total released)

4.0 Progress in reduction of releases

4.1 Total releases
- a) input total from 3.5

4.2 Releases reported in previous year
- a) input previous year's total from 3.5

4.3 Reasons for changes in quantities released:
- a) Changes in production levels
- b) Changes in estimation method
- c) Pollution prevention and abatement
- d) Other (e.g. accidents, spills or breakdowns)
- e) No significant change
- f) Up to 10 lines of text to more fully describe the reasons for a change in quantities released (optional)

4.4 Anticipated releases for the next three reporting years

5.0 Transfers of the substance in waste to off-site locations

5.1 Total quantity of substance transferred (tonnes)
5.2 Destiny of the substance (report percent of 5.1 and location code(s) from item 8)

5.2.1 Recovery/reuse/recycle
- a) Material recovery/recycle
- b) Burning/energy recovery

5.2.2 Destruction
- a) Incineration
- b) Bio-oxidation

5.2.3 Municipal sewage treatment plant
5.2.4 Containment
- a) Landfill
- b) Underground injection
- c) Other storage

6.0 Progress in reduction of transfers

6.1 Total transfers
- a) Input total from 5.1 in tonnes

6.2 Transfers reported in previous year
- a) Input previous year's total from 5.1 in tonnes

6.3 Reason for changes in quantities transferred
- a) Changes in production levels
- b) Changes in estimation method
- c) Pollution prevention and abatement
- d) Other (e.g. accidents, spills or breakdowns)
- e) No significant change
- f) Up to 10 lines of text to more fully describe the reasons for a change in quantities released (optional)

6.4 Anticipated transfers for the next three reporting years

7.0 List of names of receiving streams and water bodies

Please list the names below using one code for each stream or water body name. Enter the code(s) under item 3.3.4 in part B.

Code A: Stream name 1
Code B: Stream name 2, etc.

8.0 Identification of off-site facilities to which waste is being sent

Please list the names below using one code for each off-site waste treatment facility. Enter the code(s) under item 5.2 in part B.

Code A: Off-site facility name 1
Street address
Box number
City
Province/state/etc.
Postal code/zip code/etc.
Country

Code B: Off-site facility name 2, etc.


C

DEPARTMENT OF THE ENVIRONMENT

CANADIAN ENVIRONMENTAL PROTECTION ACT

Notice with Respect to Substances in the National Pollutant Release Inventory

Notice is hereby given that, pursuant to subsection 16(1) of the *Canadian Environmental Protection Act*, the Minister of the Environment requires, with respect to the substances listed in Schedule I to this notice, any person who owns or operates a facility described in Schedule II to this notice, and who was engaged, in 1993, in any activity described in Schedule III to this notice, and who possesses or who may reasonably be expected to have access to the types of information described in Schedule IV, to provide this information to the Minister no later than June 1, 1994.

MINISTÈRE DE L'ENVIRONNEMENT

LOI CANADIENNE SUR LA PROTECTION DE L'ENVIRONNEMENT

Avis concernant certaines substances de l'Inventaire national des rejets de polluants

Avis est par les présentes donné qu'en vertu du paragraphe 16(1) de la *Loi canadienne sur la protection de l'environnement* le ministre de l'Environnement exige, en ce qui concerne les substances figurant à l'annexe I du présent avis, que toute personne qui possède ou exploite une installation visée à l'annexe II du présent avis, qui a exercé en 1993 l'une des activités visées à l'annexe III du présent avis et qui dispose des types de renseignements visés à l'annexe IV ou peut normalement y avoir accès lui communique ces renseignements au plus tard le 1er juin 1994.

Responses to this notice shall be addressed to the Minister of the Environment, to the attention of Mr. R. Solman, Chief, Pollution Data Analysis Division, Regulatory Affairs and Program Integration Branch, Department of the Environment, Ottawa, Ontario K1A 0H3.

Pursuant to subsection 19(1) of the Act, any person who provides information in response to this notice may submit with their response a written request that it be treated as confidential.

Enquiries concerning this notice may be addressed to Mr. R. Solman at the address above or at 819-953-1656 (Telephone) or 819-953-9542 (Facsimile). Written enquiries and responses should contain the reference number DOE/CAP-241-05598.

H. A. CLARKE
Assistant Deputy Minister
Conservation and Protection
On behalf of the Minister of the Environment

Les réponses au présent avis doivent être adressées au Ministre de l'Environnement, à l'attention de M. R. Solman, Chef, Division de l'analyse des données sur la pollution, Direction des affaires réglementaires et de l'intégration des programmes, Ministère de l'Environnement, Ottawa (Ontario) K1A 0H3.

Conformément au paragraphe 19(1) de la Loi, toute personne qui fournit des renseignements en réponse au présent avis peut en même temps demander par écrit que les renseignements fournis soient considérés comme confidentiels.

Les questions au sujet du présent avis doivent parvenir à M. R. Solman à l'adresse ci-dessus ou être communiquées au 819-953-1656 (téléphone) ou au 819-953-9542 (télécopieur). Le numéro de référence ME/C&P-241-05598 doit être indiqué sur les questions et les réponses écrites.

Le sous-ministre adjoint
Conservation et Protection
H. A. CLARKE
Au nom du ministre de l'Environnement

SCHEDULE I

National Pollutant Release Inventory Substances

For. the purpose of this notice, the substances in the National Pollutant Release Inventory are (where CASRN denotes the Chemical Abstracts Service Registry Number, as appropriate):

Item	*Name*	*CASRN*
1.	Acetaldehyde	75-07-0
2.	Acetone	67-64-1
3.	Acetonitrile	75-05-8
4.	Acrylamide	79-06-1
5.	Acrylic acid	79-10-7
6.	Acrylonitrile	107-13-1
7.	Allyl alcohol	107-18-6
8.	Allyl chloride	107-05-1
9.	Aluminum (fume or dust)	7429-90-5
10.	Aluminum oxide (fibrous forms)	1344-28-1
11.	Ammonia	7664-41-7
12.	Ammonium nitrate (solution)	6484-52-2
13.	Ammonium sulfate (solution)	7783-20-2
14.	Aniline	62-53-3
15.	Anthracene	120-12-7
16.	Antimony (and its compounds)	N.A.
17.	Arsenic (and its compounds)	N.A.
18.	Asbestos	1332-21-4
19.	Benzene	71-43-2
20.	Benzoyl chloride	98-88-4
21.	Benzoyl peroxide	94-36-0
22.	Benzyl chloride	100-44-7
23.	Biphenyl	92-52-4
24.	*Bis*(2-ethylhexyl) adipate	103-23-1
25.	*Bis*(2-ethylhexyl) phthalate	117-81-7
26.	Bromomethane	74-83-9
27.	1,3-Butadiene	106-99-0
28.	Butyl acrylate	141-32-2
29.	*n*-Butyl alcohol	71-36-3
30.	*sec*-Butyl alcohol	78-92-2
31.	*tert*-Butyl alcohol	75-65-0

ANNEXE I

Substances de l'Inventaire national des rejets de polluants

Aux fins du présent avis, les substances de l'Inventaire national des rejets de polluants sont les suivantes (le nº CAS indique le numéro du Chemical Abstracts Service, le cas échéant) :

Article	*Dénomination*	*Nº CAS*
1.	Acétaldéhyde	75-07-0
2.	Acétate de 2-éthoxyéthyle	111-15-9
3.	Acétate de 2-méthoxyéthyle	110-49-6
4.	Acétate de vinyle	108-05-4
5.	Acétone	67-64-1
6.	Acétonitrile	75-05-8
7.	Acide acrylique	79-10-7
8.	Acide chloroacétique	79-11-8
9.	Acide nitrilotriacétique	139-13-9
10.	Acide nitrique	7697-37-2
11.	Acide peracétique	79-21-0
12.	Acide phosphorique	7664-38-2
13.	Acide sulfurique	7664-93-9
14.	Acrylamide	79-06-1
15.	Acrylate de butyle	141-32-2
16.	Acrylate d'éthyle	140-88-5
17.	Acrylate de méthyle	96-33-3
18.	Acrylonitrile	107-13-1
19.	Adipate de *bis*(2-éthylhexyle)	103-23-1
20.	Alcool allylique	107-18-6
21.	Aluminium (fumée ou poussière)	7429-90-5
22.	Amiante	1332-21-4
23.	Ammoniaque	7664-41-7
24.	Anhydride maléique	108-31-6
25.	Anhydride phthalique	85-44-9
26.	Aniline	62-53-3
27.	Anthracène	120-12-7
28.	Antimoine (et ses composés)	s.o.
29.	Argent (et ses composés)	s.o.
30.	Arsenic (et ses composés)	s.o.
31.	Benzène	71-43-2

Item	*Name*	*CASRN*
32.	Butyl benzyl phthalate	85-68-7
33.	1,2-Butylene oxide	106-88-7
34.	Butyraldehyde	123-72-8
35.	C.I. Acid Green 3	4680-78-8
36.	C.I. Basic Green 4	569-64-2
37.	C.I. Basic Red 1	989-38-8
38.	C.I. Disperse Yellow 3	2832-40-8
39.	C.I. Food Red 15	81-88-9
40.	C.I. Solvent Orange 7	3118-97-6
41.	C.I. Solvent Yellow 14	842-07-9
42.	Cadmium (and its compounds)	N.A.
43.	Calcium cyanamide	156-62-7
44.	Carbon disulfide	75-15-0
45.	Carbon tetrachloride	56-23-5
46.	Catechol	120-80-9
47.	Chlorine	7782-50-5
48.	Chlorine dioxide	10049-04-4
49.	Chloroacetic acid	79-11-8
50.	Chlorobenzene	108-90-7
51.	Chloroethane	75-00-3
52.	Chloroform	67-66-3
53.	Chloromethane	74-87-3
54.	Chloromethyl methyl ether	107-30-2
55.	Chromium (and its compounds)	N.A.
56.	Cobalt (and its compounds)	N.A.
57.	Copper (and its compounds)	N.A.
58.	Cresol (mixed isomers)	1319-77-3
59.	*m*-Cresol	108-39-4
60.	*o*-Cresol	95-48-7
61.	*p*-Cresol	106-44-5
62.	Cumene	98-82-8
63.	Cumene hydroperoxide	80-15-9
64.	Cyanides (ionic)	N.A.
65.	Cyclohexane	110-82-7
66.	Decabromodiphenyl oxide	1163-19-5
67.	2,4-Diaminotoluene	95-80-7
68.	Dibutyl phthalate	84-74-2
69.	*o*-Dichlorobenzene	95-50-1
70.	*p*-Dichlorobenzene	106-46-7
71.	1,2-Dichloroethane	107-06-2
72.	Dichloromethane	75-09-2
73.	2,4-Dichlorophenol	120-83-2
74.	1,2-Dichloropropane	78-87-5
75.	Diethanolamine	111-42-2
76.	Diethyl phthalate	84-66-2
77.	Diethyl sulfate	64-67-5
78.	Dimethyl phthalate	131-11-3
79.	Dimethyl sulfate	77-78-1
80.	4,6-Dinitro-*o*-cresol	534-52-1
81.	2,4-Dinitrotoluene	121-14-2
82.	2,6-Dinitrotoluene	606-20-2
83.	Dinitrotoluene (mixed isomers)	25321-14-6
84.	Di-*n*-octyl phthalate	117-84-0
85.	1,4-Dioxane	123-91-1
86.	Epichlorohydrin	106-89-8
87.	2-Ethoxyethanol	110-80-5
88.	2-Ethoxyethyl acetate	111-15-9
89.	Ethyl acrylate	140-88-5
90.	Ethylbenzene	100-41-4
91.	Ethyl chloroformate	541-41-3
92.	Ethylene	74-85-1
93.	Ethylene glycol	107-21-1
94.	Ethylene oxide	75-21-8
95.	Ethylene thiourea	96-45-7
96.	Formaldehyde	50-00-0

Article	*Dénomination*	*N° CAS*
32.	Biphényle	92-52-4
33.	Bromométhane	74-83-9
34.	Buta-1,3-diène	106-99-0
35.	Butan-1-ol	71-36-3
36.	Butan-2-ol	78-92-2
37.	Butyraldéhyde	123-72-8
38.	Cadmium (et ses composés)	s.o.
39.	Catéchol	120-80-9
40.	Cétone de Michler	90-94-8
41.	Chlore	7782-50-5
42.	Chlorobenzène	1088-90-7
43.	Chloroéthane	75-00-3
44.	Chloroforme	67-66-3
45.	Chloroformiate d'éthyle	541-41-3
46.	Chlorométhane	74-87-3
47.	Chlorure d'allyle	107-05-1
48.	Chlorure de benzoyle	98-88-4
49.	Chlorure de benzyle	100-44-7
50.	Chlorure d'hydrogène	7647-01-0
51.	Chlorure de vinyle	75-01-4
52.	Chlorure de vinylidène	75-35-4
53.	Chrome (et ses composés)	s.o.
54.	Cobalt (et ses composés)	s.o.
55.	Crésol (mélange d'isomères)	1319-77-3
56.	*m*-Crésol	108-39-4
57.	*o*-Crésol	95-48-7
58.	*p*-Crésol	106-44-5
59.	Cuivre (et ses composés)	s.o.
60.	Cumène	98-82-8
61.	Cyanamide calcique	156-62-7
62.	Cyanides (ioniques)	s.o.
63.	Cyanure d'hydrogène	74-90-8
64.	Cyclohexane	110-82-7
65.	2,4-Diaminotoluène	95-80-7
66.	*o*-Dichlorobenzène	95-50-1
67.	*p*-Dichlorobenzène	106-46-7
68.	1,2-Dichloroéthane	107-06-2
69.	Dichlorométhane	75-09-2
70.	2,4-Dichlorophénol	120-83-2
71.	1,2-Dichloropropane	78-87-5
72.	Diéthanolamine	111-42-2
73.	N,N-Diméthylaniline	121-69-7
74	4,6-Dinitro-*o*-crésol	534-52-1
75.	Dinitrotoluène (mélange d'isomères)	25321-14-6
76.	2,4-Dinitrotoluène	121-14-2
77	2,6-Dinitrotoluène	606-20-2
78.	1,4-Dioxane	123-91-1
79.	Dioxyde de chlore	10049-04-4
80.	Dioxyde de thorium	1314-20-1
81.	Disulfure de carbone	75-15-0
82.	Épichlorohydrine	106-89-8
83.	1,2-Époxybutane	106-88-7
84.	Éthane-1,2-diol	107-21-1
85.	2-Éthoxyéthanol	110-80-5
86.	Éthylbenzène	100-41-4
87.	Éthylène	74-85-1
88.	Fluorure d'hydrogène	7664-39-3
89.	Formaldéhyde	50-00-0
90.	Hexachlorocyclopentadiène	77-47-4
91.	Hexachloroéthane	67-72-1
92.	Hydrazine	302-01-2
93.	Hydroperoxide de cumène	80-15-9
94.	Hydroquinone	123-31-9
95.	Imidazolidine-2-thione	96-45-7
96.	Indice de couleur jaune de dispersion 3	2832-40-8

Item	*Name*	*CASRN*
97.	Hexachlorocyclopentadiene	77-47-4
98.	Hexachloroethane	67-72-1
99.	Hydrazine	302-01-2
100.	Hydrochloric acid	7647-01-0
101.	Hydrogen cyanide	74-90-8
102.	Hydrogen fluoride	7664-39-3
103.	Hydroquinone	123-31-9
104.	Isobutyraldehyde	78-84-2
105.	Isopropyl alcohol	67-63-0
106.	4,4-Isopropylidenediphenol	80-05-7
107.	Isosafrole	120-58-1
108.	Lead (and its compounds)	N.A.
109.	Maleic anhydride	108-31-6
110.	Manganese (and its compounds)	N.A.
111.	Mercury (and its compounds)	N.A.
112.	Methanol	67-56-1
113.	2-Methoxyethanol	109-86-4
114.	2-Methoxyethyl acetate	110-49-6
115.	Methyl acrylate	96-33-3
116.	Methyl *tert*-butyl ether	1634-04-4
117.	4,4'-Methylene*bis* (2-chloroaniline)	101-14-4
118.	Methylene*bis* (phenylisocyanate)	101-68-8
119.	4,4'-Methylenedianiline	101-77-9
120.	Methyl ethyl ketone	78-93-3
121.	Methyl iodide	74-88-4
122.	Methyl isobutyl ketone	108-10-1
123.	Methyl methacrylate	80-62-6
124.	Michler's ketone	90-94-8
125.	Molybdenum trioxide	1313-27-5
126.	Naphthalene	91-20-3
127.	Nickel (and its compounds)	N.A.
128.	Nitric acid	7697-37-2
129.	Nitrilotriacetic acid	139-13-9
130.	Nitrobenzene	98-95-3
131.	Nitroglycerin	55-63-0
132.	*p*-Nitrophenol	100-02-7
133.	2-Nitropropane	79-46-9
134.	N,N-Dimethylaniline	121-69-7
135.	N-Nitrosodiphenylamine	86-30-6
136.	Peracetic acid	79-21-0
137.	Phenol	108-95-2
138.	*p*-Phenylenediamine	106-50-3
139.	*o*-Phenylphenol	90-43-7
140.	Phosgene	75-44-5
141.	Phosphoric acid	7664-38-2
142.	Phosphorus (yellow or white)	7723-14-0
143.	Phthalic anhydride	85-44-9
144.	Propionaldehyde	123-38-6
145.	Propylene	115-07-1
146.	Propylene oxide	75-56-9
147.	Pyridine	110-86-1
148.	Quinoline	91-22-5
149.	*p*-Quinone	106-51-4
150.	Safrole	94-59-7
151.	Selenium (and its compounds)	N.A.
152.	Silver (and its compounds)	N.A.
153.	Styrene	100-42-5
154.	Styrene oxide	96-09-3
155.	Sulfuric acid	7664-93-9
156.	1,1,2,2-Tetrachloroethane	79-34-5
157.	Tetrachloroethylene	127-18-4
158.	Thiourea	62-56-6
159.	Thorium dioxide	1314-20-1
160.	Titanium tetrachloride	7550-45-0
161.	Toluene	108-88-3

Article	*Dénomination*	*N° CAS*
97.	Indice de couleur jaune de solvant 14	842-07-09
98.	Indice de couleur orange de solvant 7	3118-9
99.	Indice de couleur rouge alimentaire 15	81-88-9
100.	Indice de couleur rouge de base 1	989-38-8
101.	Indice de couleur vert acide 3	4680-78-8
102.	Indice de couleur vert de base 4	569-64-2
103.	Iodométhane	74-88-4
104.	Isobutyraldéhyde	78-84-2
105.	4,4-Isopropylidènediphénol	80-05-7
106.	Isosafrole	120-58-1
107.	Manganèse (et ses composés)	s.o.
108.	Mercure (et ses composés)	s.o.
109.	Méthacrylate de méthyle	80-62-6
110.	Méthanol	67-56-1
111.	2-Méthoxyéthanol	109-86-4
112.	Méthyle éthyle cétone	78-93-3
113.	Méthyle isobutyle cétone	108-10-1
114.	4,4'-Méthylène*bis*(2-chloroaniline)	101-14-4
115.	Méthylène*bis*(phénylisocyanate)	101-68-8
116.	4,4'-Méthylènedianiline	101-77-9
117.	2-Méthylpropan-2-ol	75-65-0
118.	Naphthalène	91-20-3
119.	Nickel (et ses composés)	s.o.
120.	Nitrate d'ammonium (solution)	6484-52-2
121.	Nitrobenzène	98-95-3
122.	Nitroglycérine	55-63-0
123.	*p*-Nitrophénol	100-02-7
124.	2-Nitropropane	79-46-9
125.	N-Nitrosodiphénylamine	86-30-6
126.	Oxyde d'aluminium (formes fibreuses)	1344-28-1
127.	Oxyde de chlorométhyle et de méthyle	107-30-2
128.	Oxyde de décabromodiphényle	1163-19-5
129.	Oxyde d'éthylène	75-21-8
130.	Oxyde de propylène	75-56-9
131.	Oxyde de styrène	96-09-3
132.	Oxyde de *tert*-butyle et de méthyle	1634-04-4
133.	Peroxyde de benzoyle	94-36-0
134.	Phénol	108-95-2
135.	*p*-Phénylènediamine	106-50-3
136.	*o*-Phénylphénol	90-43-7
137.	Phosgène	75-44-5
138.	Phosphore (jaune ou blanc)	7723-14-0
139.	Phtalate de benzyle et de butyle	85-68-7
140.	Phtalate de *bis*(2-éthylhexyle)	117-81-7
141.	Phtalate de dibutyle	84-74-2
142.	Phtalate de diéthyle	84-66-2
143.	Phtalate de diméthyle	131-11-3
144.	Phtalate de dioctyle	117-84-0
145.	Plomb (et ses composés)	s.o.
146.	Propan-2-ol	67-63-0
147.	Propionaldéhyde	123-38-6
148.	Propylène	115-07-1
149.	Pyridine	110-86-1
150.	Quinoline	91-22-5
151.	*p*-Quinone	106-51-4
152.	Safrole	94-59-7
153.	Sélénium (et ses composés)	s.o.
154.	Sulfate d'ammonium (solution)	7783-20-2
155.	Sulfate de diéthyle	64-67-5
156.	Sulfate de diméthyle	77-78-1
157.	Styrène	100-42-5
158.	1,1,2,2-Tétrachloroéthane	79-34-5
159.	Tétrachloroéthylène	127-18-4
160.	Tétrachlorure de carbone	56-23-5
161.	Tétrachlorure de titane	7550-45-0

Item	Name	CASRN
162.	Toluene-2,4-diisocyanate	584-84-9
163.	Toluene-2,6-diisocyanate	91-08-7
164.	Toluenediisocyanate (mixed isomers)	26471-62-5
165.	1,2,4-Trichlorobenzene	120-82-1
166.	1,1,2-Trichloroethane	79-00-5
167.	Trichloroethylene	79-01-6
168.	1,2,4-Trimethylbenzene	95-63-6
169.	Vanadium (fume or dust)	7440-62-2
170.	Vinyl acetate	108-05-4
171.	Vinyl chloride	75-01-4
172.	Vinylidene chloride	75-35-4
173.	Xylene (mixed isomers)	1330-20-7
174.	*m*-Xylene	108-38-3
175.	*o*-Xylene	95-47-6
176.	*p*-Xylene	106-42-3
177.	Zinc (and its compounds)	N.A.
178.	Zinc (fume or dust)	7440-66-6

Article	Dénomination	N° CAS
162.	Thiourée	62-56-6
163.	Toluène	108-88-3
164.	Toluènediisocyanate (mélange d'isomères)	26471-62-5
165.	Toluène-2,4-diisocyanate	584-84-9
166.	Toluène-2,6-diisocyanate	91-08-7
167.	1,2,4-Trichlorobenzène	120-82-1
168.	1,1,2-Trichloroéthane	79-00-5
169.	Trichloroéthylène	79-01-6
170.	1,2,4-Triméthylebenzène	95-63-6
171.	Trioxyde de molybdène	1313-27-5
172.	Vanadium (fumée ou poussière)	7440-62-2
173.	Xylène (mélange d'isomères)	1330-20-7
174.	*m*-Xylène	108-38-3
175.	*o*-Xylène	95-47-6
176.	*p*-Xylène	106-42-3
177.	Zinc (et ses composés)	s.o.
178.	Zinc (fumée ou poussière)	7440-66-6

SCHEDULE II

Reporting Facilities

For the purpose of this notice, a "facility" means all buildings, equipment, structures and other stationary items which are located on a single site or on contiguous or adjacent sites which are owned or operated by the same person and at which employees worked a total of not less than 20 000 hours during 1993. This definition does not include any facility or any part thereof which is used exclusively for:

1. Manufacturing, processing or otherwise using any substance listed in Schedule I to this notice at concentrations of less than one per cent by weight;
2. Manufacturing, processing or otherwise using less than 10 tonnes of substances listed in Schedule I to this notice during 1993;
3. Education or training of students, such as universities, colleges, and schools;
4. Research on or testing of substances listed in Schedule I to this notice;
5. The maintenance and repair of transportation vehicles, such as automobiles, trucks, locomotives, ships or aircraft;
6. The distribution, storage, or retail sale of fuels;
7. The wholesale or retail sale of articles or products which contain substances listed in Schedule I to this notice, as long as the substances are not released to the environment during normal use at the facility;
8. The retail sale of substances listed in Schedule I to this notice;
9. Growing, harvesting, or management of renewable natural resources, such as fisheries, forestry or agriculture, as opposed to facilities which process or otherwise use their products;

ANNEXE II

Installations tenues de communiquer des renseignements

Aux fins du présent avis, «installation» s'entend des bâtiments, équipement, ouvrages ou autres articles stationnaires situés dans un site unique ou sur des sites contigus ou adjacents, que la même personne possède ou exploite et dont les employés ont travaillé pendant au moins 20 000 heures en 1993. Cette définition exclut les installations ou parties d'installations qui servent uniquement aux fins suivantes :

1. la fabrication, le traitement ou l'utilisation d'une autre manière des substances figurant à l'annexe I du présent avis en concentrations de moins de un pour cent en masse;
2. la fabrication, le traitement ou l'utilisation d'une autre manière des substances figurant à l'annexe I du présent avis en une quantité inférieure à 10 tonnes en 1993;
3. l'éducation ou la formation des étudiants, notamment les universités, les collèges et les écoles;
4. la recherche ou les essais relatifs aux substances figurant à l'annexe I du présent avis;
5. l'entretien et la réparation de véhicules de transport, notamment les automobiles, les camions, les locomotives, les navires ou les aéronefs;
6. la distribution, le stockage ou la vente au détail de carburants;
7. la vente en gros ou au détail d'articles ou de produits contenant des substances figurant à l'annexe I du présent avis, à condition qu'elles ne soient pas rejetées dans l'environnement au cours de leur utilisation normale dans l'installation;
8. la vente au détail de substances figurant à l'annexe I du présent avis;
9. la culture, la récolte ou la gestion de ressources naturelles renouvelables, notamment la pêche, les forêts ou l'agriculture, par opposition aux installations qui traitent ou utilisent leurs produits d'une autre manière;

10. Mining of materials which contain substances listed in Schedule I to this notice, but not those facilities engaged in further processing of these mined materials;

11. Drilling or operating wells to obtain oil and gas products which contain substances listed in Schedule I to this notice, but not those facilities engaged in further processing of these oil and gas products.

10. l'extraction de matières contenant des substances figurant à l'annexe I du présent avis, à l'exclusion des installations qui traitent ultérieurement ces matières extraites;

11. le forage ou l'exploitation de puits pour l'obtention de produits du pétrole ou du gaz contenant des substances figurant à l'annexe I du présent avis, à l'exclusion des installations qui traitent ultérieurement ces produits du pétrole ou du gaz.

SCHEDULE III

Activities

1. "Manufacture" To produce, prepare, compound or import a substance listed in Schedule I. The term "manufacture" includes the generation of a listed substance as a by-product or impurity.

2. "Process" The preparation of a substance listed in Schedule I, after its manufacture, for distribution in commerce. Processing includes preparation of a substance in the same physical state or chemical form as that received by the facility, or preparation that produces a change in physical state or chemical form.

3. "Otherwise Use" Any use of a substance listed in Schedule I at a facility that is not included under the definitions of "manufacture" or "process".

ANNEXE III

Activités

1. «Fabrication» La production, la préparation, la composition ou l'importation d'une substance figurant à l'annexe I. Le terme «fabrication» comprend la génération d'une substance figurant à l'annexe I en tant que sous-produit ou impureté.

2. «Traitement» La préparation d'une substance figurant à l'annexe I après sa fabrication, en vue de sa distribution dans le commerce. Le traitement comprend les préparations d'une substance conservant l'état physique ou la formule chimique qu'elle avait à sa réception à l'installation et celles qui produisent un changement de son état physique ou de sa formule chimique.

3. «Utilisation d'une autre manière» Toute utilisation, dans une installation, d'une substance figurant à l'annexe I, qui n'est pas comprise dans les définitions de «fabrication» ou de «traitement».

SCHEDULE IV

Types of Information Subject to Notice

Note: Facilities which are required to provide information in response to this notice must do so in the manner specified in the guidance document "Reporting to the 1993 National Pollutant Release Inventory", which will be mailed to reporting facilities in mid-1993.

If your facility meets the reporting criteria and you have not received the above guidance document by June 1, 1993, you should request a copy from Mr. R. Solman, whose address and telephone number are listed in this notice.

For the purposes of this notice, the types of reportable information include:

1. Facility identification, including name, number of full-time employees, location, street address, mailing address, identification of a facility contact, and name of a responsible official, together with other unique identifiers which may be available for the facility;

2. Identity of each substance or class of substance listed in Schedule I to this notice, including its Chemical Abstracts Service Registry Number, if applicable, the

ANNEXE IV

Types de renseignements assujettis à l'avis

Nota : Les installations qui sont tenues de communiquer des renseignements en réponse au présent avis doivent le faire conformément au guide intitulé «Rapport de l'Inventaire national des rejets de polluants de 1993», qui sera expédié par la poste au milieu de 1993 aux installations visées.

Si votre installation est tenue de communiquer des renseignements et que vous n'avez pas reçu le guide mentionné ci-dessus le 1er juin 1993, vous devriez en demander un exemplaire à M. R. Solman, dont l'adresse et le numéro de téléphone sont indiqués dans le présent avis.

Aux fins du présent avis, les types de renseignements communicables sont les suivants :

1. des renseignements sur l'installation, y compris le nom, le nombre d'employés à plein temps, l'emplacement, l'adresse physique, l'adresse postale, le nom d'une personne-ressource de l'installation et d'une personne responsable, ainsi que les autres caractéristiques disponibles concernant l'installation;

2. la dénomination de chaque substance ou catégorie de substances figurant à l'annexe I du présent avis, accompagnée le cas échéant du numéro du Chemical

nature of activities (manufacture, process, or otherwise use) involving each substance or class of substances, and estimates of the amounts of on-site releases to air, water, underground injection, and land, subdivided by types of release and times of release (if releases have a significant seasonal variation);

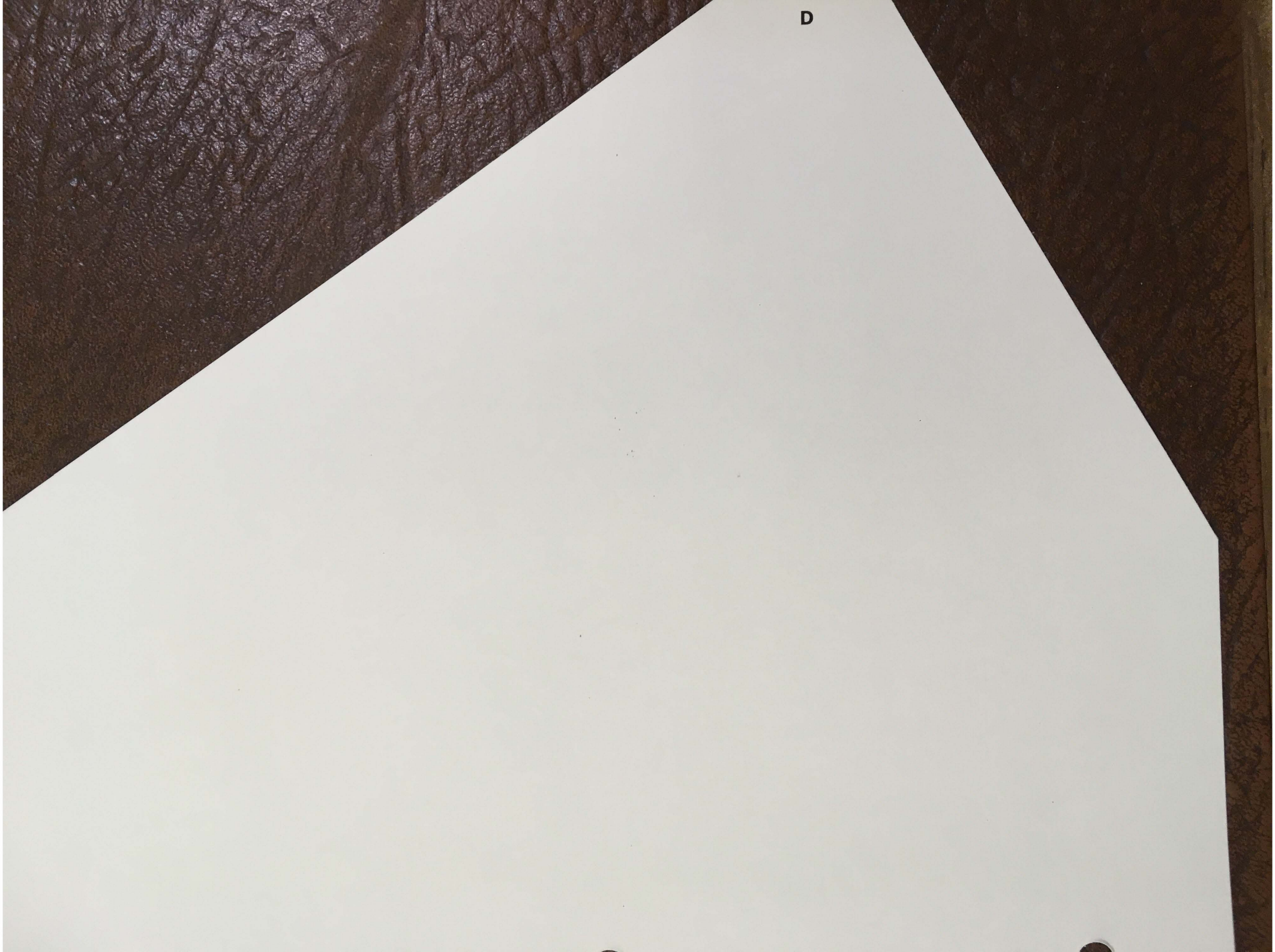
3. Anticipated changes in on-site releases of each reported substance for the next three years;
4. Estimated quantity of each reported substance in wastes transferred to off-site locations, subdivided by the nature of treatment, destruction or containment of these wastes;
5. Anticipated changes in off-site transfers of each reported substance for the next three years;
6. Identification of off-site facilities to which wastes containing substances listed in Schedule I to this notice are transferred;
7. Identification of reported information which is claimed as confidential, pursuant to subsection 19(1) of the *Canadian Environmental Protection Act*.

[13-1-o]

Abstracts Service, la nature des activités (fabrication, traitement ou utilisation d'une autre manière) relatives à chaque substance ou catégorie de substances et des estimations des quantités rejetées sur le site dans l'air, dans l'eau, par injection dans le sous-sol, et dans le sol, classées par types de rejet et dates de rejet (si les rejets connaissent des variations saisonnières importantes);

3. les changements prévus liés aux rejets sur le site de chaque substance déclarée au cours des trois prochaines années;
4. la quantité estimative de chaque substance déclarée dans les déchets transférés à d'autres sites, classée en fonction de la nature du traitement, de la destruction ou du confinement de ces déchets;
5. les changements prévus liés aux transferts à d'autres sites de chaque substance déclarée au cours des trois prochaines années;
6. le nom des installations à l'extérieur du site où sont transférés les déchets contenant des substances figurant à l'annexe I du présent avis;
7. une mention quant aux renseignements communiqués qui sont visés par une demande pour qu'ils soient considérés comme confidentiels conformément au paragraphe 19(1) de la *Loi canadienne sur la protection de l'environnement*.


B


D

	A	B	C	D	E	F	G	H	I	J	K	L
1	**Chemical Substance Release Inventories**											
2		(Revised: June 14, 1993)										
3	**LEGEND**											
4	NPRI - Based on Gazette of March 27, 1993 (note changes)											
5	ECI - Substances requested by Exxon Company International											
6	(NOTE: ECI is also requesting fuel in tonnes, mases of various waste streams,											
7	and releases from categories not broken out by NPRI)											
8	33/50 - US voluntary reduction program											
9	Ont BAN - Ontario ban and phaseout lists											
10	PSL - Canadian Priority Substance Lists											
11	(PAH substances identified based on Tom Dann'sPMD-89-14)											
12	NERM-Canadian Chemical Producers Association;National Emission Reduction Masterplan											
13	TRI - US Toxic Release Inventory; 93/6: TRI'- those with 0.1 de minimus (vs 1.0)											
14	Ref - incomplete list of substances reported by US refineries as part of TRI requirements											
15	Pattern indicates flagged by CPPI											
16	Spill - Environment Canada 1990 Chemical Spill Priority List											
17	S<10 indicates in top 10; <25 indicates top 25											
18												
19	TRI Chemicals	CAS #	NPRI	ECI	33/50	OntBAN	PSL	NERM	Spill	Ref	TRI	TRI'
20	1,1,1-Trichloroethane (Methyl chloroform)	71556						NERM			TRI	
21	1,1,2,2-Tetrachloroethane	79345	NPRI		33/50			NERM			TRI	0.1
22	1,1,2-Trichloroethane	79005	NPRI					NERM			TRI	
23	1,1-Dimethyl hydrazine	57147						NERM			TRI	0.1
24	1,2 Dichlorobenzene						PSL					
25	1,2 Dichloropropane	78875	NPRI					NERM			TRI	
26	1,2,3,5-tetrachlorobenzene	634902				Ban"						
27	1,2,3-Trichlorobenzene	87616				Ban"						
28	1,2,4-Trichlorobenzene	120821	NPRI					NERM			TRI	
29	1,2,4-Trimethylbenzene	95636	NPRI					NERM			TRI	
30	1,2-Butylene oxide	106887	NPRI					NERM			TRI	
31	1,2-Dibromo-3-chloropropane	96128						NERM			TRI	0.1
32	1,2-Dibromoethane (Ethylene dibromide)	106934				Ban"		NERM			TRI	0.1
33	1,2-Dichloroethane (Ethylene dichloride)	107062	NPRI					NERM			TRI	0.1
34	1,2-Dichloroethylene	540590						NERM			TRI	
35	1,2-Diphenylhydrazine	122667				Ban"		NERM			TRI	0.1
36	1,3-Butadiene	106990	NPRI					NERM		Ref	TRI	0.1

	A	B	C	D	E	F	G	H	I	J	K	L
37	1,3-Dichlorobenzene	541731						NERM			TRI	
38	1,3-Dichloropropylene	542756						NERM			TRI	0.1
39	1,4-Dioxane	123911	NPRI			Ban"		NERM			TRI	0.1
40	1,8-dinitropyrene	42397659				Ban"						
41	1-Amino-2-methylanthraquinone	82280						NERM			TRI	0.1
42	1-Butene	106989						NERM				
43	1-Hexene	592416						NERM				
44	1-Methyl-Pyrene						PAH					
45	1-Pentene	109671						NERM				
46	2,3 Dichloropropene	78886						NERM			TRI	
47	2,3,4,5-Tetrachlorophenol	4901513				Ban"						
48	2,3,4,6-tetrachlorophenol	58902				Ban"						
49	2,3-Dimethylbutane	79298						NERM				
50	2,4,5-Trichlorophenol	95954				Ban"		NERM			TRI	
51	2,4,6-Trichlorophenol	88062						NERM			TRI	0.1
52	2,4-D	94757						NERM			TRI	
53	2,4-Diaminoanisole	615054						NERM			TRI	0.1
54	2,4-Diaminoanisole sulfate	39156417						NERM			TRI	0.1
55	2,4-Diaminotoluene	95807	NPRI					NERM			TRI	0.1
56	2,4-Dichlorophenol	120832	NPRI					NERM			TRI	
57	2,4-Dimethylphenol	105679						NERM			TRI	
58	2,4-Dinitrophenol	51285						NERM			TRI	
59	2,4-Dinitrotoluene	121142	NPRI					NERM			TRI	
60	2,6-Dinitrotoluene	606202	NPRI					NERM			TRI	
61	2,6-Xylidene	87627						NERM			TRI	
62	2-Acetylaminofluorene	53963						NERM			TRI	0.1
63	2-Aminoanthraquinone	117793						NERM			TRI	0.1
64	2-Chloroacetophenone	532274						NERM			TRI	
65	2-Ethoxyethanol	110805	NPRI					NERM			TRI	
66	2-Ethoxyethyl acetate (3)	111159	NPRI									
67	2-Methoxyethanol	109864	NPRI					NERM			TRI	
68	2-Methoxyethyl acetate (3)	110496	NPRI									
69	2-Methyl-Cholanthrene						PAH					
70	2-Methyl-Fluorene						PAH					
71	2-Methylpropene (isabutylene)	115117						NERM				
72	2-Nitrophenol	88755						NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
73	2-Nitropropane	79469	NPRI					NERM			TRI	0.1
74	3,3'-Dichlorobenzidine	91941				Ban'	PSL	NERM			TRI	0.1
75	3,3-Dimethoxybenzidine	119904						NERM			TRI	0.1
76	3,3-Dimethylbenzidine	119937						NERM			TRI	0.1
77	3,5 Dimethylaniline						PSL					
78	4,4'-Diaminodiphenyl ether	101804						NERM			TRI	0.1
79	4,4'-Methylenedianiline (1)	101779	NPRI					NERM			TRI	0.1
80	4,4'-Thiodianiline	139651						NERM			TRI	0.1
81	4,4-Isopropylidenediphenol	80057	NPRI					NERM			TRI	
82	4,4-Methylene bis (N,N-dimethyl) benzenamine	101611						NERM			TRI	0.1
83	4,4-Methylenebis (2-chloro aniline) (1)	101144	NPRI					NERM			TRI	0.1
84	4,6-Dinitro-o-cresol	534521	NPRI					NERM			TRI	
85	4-Aminoazobenzene	60093						NERM			TRI	0.1
86	4-Aminobiphenyl	92671						NERM			TRI	0.1
87	4-Chlorophenyl phenyl ether (1-chloro-4-phenoxybenzene)	7005723				Ban"						
88	4-Dimethylaminoazobenzene	60117						NERM			TRI	0.1
89	4-Nitrobiphenyl	92933						NERM			TRI	0.1
90	5-Nitro-o-anisidine	99592						NERM			TRI	0.1
91	7,12-dimethylbenz[a]anthracene	57976				Ban"	PAH					
92	7H-dibenzo[c,g]carbazole	194592				Ban"						
93	a-1,2,3,4,5,6 Hexachlorocyclohexane	319846				Ban'						
94	Acenapthene						PAH					
95	Acenapthylene						PAH					
96	Acetaldehyde	75070	NPRI					NERM			TRI	0.1
97	Acetamide	60355						NERM			TRI	0.1
98	Acetone	67641	NPRI					NERM			TRI	
99	Acetonitrile	75058	NPRI					NERM			TRI	
100	Acetylene	74862						NERM				
101	Acrolein	107028						NERM			TRI	0.1
102	Acrylamide	79061	NPRI					NERM			TRI	0.1
103	Acrylic acid	79107	NPRI					NERM			TRI	
104	Acrylonitrile	107131	NPRI					NERM			TRI	0.1
105	Aldrin	309002						NERM			TRI	
106	Allyl alcohol	107186	NPRI					NERM			TRI	
107	Allyl chloride	107051	NPRI					NERM			TRI	
108	alpha-Naphthylamine	134327						NERM			TRI	0.1

	A	B	C	D	E	F	G	H	I	J	K	L
109	Aluminum (fume or dust)	7429905	NPRI			Ban"		NERM			TRI	
110	Aluminum oxide (fibrous form)	1344281	NPRI					NERM			TRI	0.1
111	Ammonia	7664417	NPRI					NERM	S<1	Ref	TRI	
112	Ammonium hydroxide								S<25			
113	Ammonium nitrate (solution)	6484522	NPRI					NERM			TRI	
114	Ammonium sulfate (solution)	7783202	NPRI					NERM	S<25		TRI	
115	Aniline	62533	NPRI				PSL	NERM			TRI	
116	Anthracene	120127	NPRI			Ban'	PAH	NERM		Ref	TRI	
117	Anthranene						PAH					
118	Antimony	7440360	NPRI					NERM			TRI	
119	Antimony compounds		NPRI								TRI	
120	Arsenic	7440382	NPRI			Ban'	PSL	NERM			TRI	0.1
121	Arsenic compounds		NPRI								TRI	
122	Asbestos (friable)	1332214	NPRI					NERM			TRI	0.1
123	Barium	7440393						NERM			TRI	
124	Barium compounds										TRI	
125	Benzal chloride	98873						NERM			TRI	
126	Benzamide	55210						NERM			TRI	
127	Benzene	71432	NPRI		33/50			NERM	S<2	Ref	TRI	0.1
128	Benzidine	92875					PSL	NERM			TRI	0.1
129	Benzoic trichloride	98077						NERM			TRI	0.1
130	Benzoyl chloride	98884	NPRI					NERM			TRI	
131	Benzoyl peroxide	94360	NPRI					NERM			TRI	
132	Benzo[a]anthracene	56553				Ban'	PAH					
133	Benzo[a]fluorene						PAH					
134	Benzo[a]pyrene	50328				Ban'	PAH					
135	Benzo[a]pyrene						PAH					
136	Benzo[b]chrysene						PAH					
137	Benzo[b]fluoranthene	205992				Ban"	PAH					
138	Benzo[b]fluorene						PAH					
139	Benzo[e]perylene	192972				Ban"						
140	Benzo[g,h,i]fluoranthene						PAH					
141	Benzo[ghi]perylene	191242				Ban'	PAH					
142	Benzo[j]fluoranthene	205823				Ban"						
143	Benzo[k]fluoranthene	207089				Ban"	PAH					
144	Benzyl chloride	100447	NPRI					NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
145	Beryllium	7440417				Ban"		NERM			TRI	0.1
146	Beryllium compounds										TRI	
147	beta-Naphthylamine	91598						NERM			TRI	0.1
148	beta-Propiolactone	57578						NERM			TRI	0.1
149	Biphenyl	92524	NPRI					NERM			TRI	
150	Bis (2-ethylhexyl) phthalate						PSL					
151	Bis(2-chloro-1-methylethyl)ether	108601						NERM			TRI	
152	Bis(2-chloroethyl)ether	111444						NERM			TRI	
153	Bis(2-ethylhexyl)adipate	103231	NPRI					NERM			TRI	
154	Bis(2-ethylhexyl)phthalate (1)	117817	NPRI			Ban"		NERM			TRI	0.1
155	Bis(chloromethyl)ether	542881						NERM			TRI	0.1
156	Bromochlorodifluoromethane (Halon 1211)	353593									TRI	
157	Bromoform (Tribromomethane)	75252						NERM			TRI	
158	Bromomethane (Methyl bromide)	74839	NPRI					NERM			TRI	
159	Bromotrifluoromethane (Halon)	75638									TRI	
160	Butyl acrylate	141322	NPRI					NERM			TRI	
161	Butyl benzyl phthalate	85687	NPRI					NERM			TRI	
162	Butyraldehyde	123728	NPRI					NERM			TRI	
163	C.I. Acid Green 3	4680788	NPRI					NERM			TRI	
164	C.I. Basic Green 4	569642	NPRI					NERM			TRI	
165	C.I. Basic Red 1	989388	NPRI					NERM			TRI	0.1
166	C.I. Direct Black 38	1937377						NERM			TRI	0.1
167	C.I. Direct Blue 6	2602462						NERM			TRI	0.1
168	C.I. Direct Brown 95	16071866						NERM			TRI	0.1
169	C.I. Disperse Yellow 3	2832408	NPRI					NERM			TRI	
170	C.I. Food Red 15	81889	NPRI					NERM			TRI	0.1
171	C.I. Food Red 5	3761533						NERM			TRI	0.1
172	C.I. Solvent Orange 7	3118976	NPRI					NERM			TRI	
173	C.I. Solvent Yellow 14	842079	NPRI					NERM			TRI	0.1
174	C.I. Solvent Yellow 3	97563						NERM			TRI	0.1
175	C.I. Solvent Yellow 34	492808						NERM			TRI	0.1
176	C.I. Vat Yellow 4	128665						NERM			TRI	
177	Cadmium	7440439	NPRI		33/50	Ban"	PSL	NERM			TRI	0.1
178	Cadmium compounds		NPRI		33/50						TRI	
179	Calcium chloride								S<25			
180	Calcium cyanamide	156627	NPRI					NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
181	Calcium hypochlorite								S<25			
182	Captan	133062						NERM			TRI	
183	Carbaryl	63252						NERM			TRI	
184	Carbon Dioxide	124389		ECI				NERM				
185	Carbon disulfide	75150	NPRI		33/50			NERM			TRI	
186	Carbon Monoxide			ECI								
187	Carbon tetrachloride	56235	NPRI					NERM		Ref	TRI	0.1
188	Carbonyl sulfide	463581						NERM			TRI	
189	Catechol	120809	NPRI					NERM			TRI	
190	Chloramben	133904						NERM			TRI	
191	Chlordane	57749						NERM			TRI	
192	Chlorinated Paraffins						PSL					
193	Chlorine	7782505	NPRI					NERM	S<1	Ref	TRI	
194	Chlorine dioxide	10049044	NPRI					NERM			TRI	
195	Chloroacetic acid	79118	NPRI					NERM			TRI	
196	Chloroalkyl Ethers (x3)						PSL					
197	Chlorobenzene	108907	NPRI			Ban"		NERM			TRI	
198	Chlorobenzilate	510156						NERM			TRI	
199	Chloroethane (Ethyl chloride)	75003	NPRI					NERM			TRI	
200	Chloroform	67663	NPRI		33/50			NERM			TRI	0.1
201	Chloromethane (Methyl chloride)	74873	NPRI					NERM			TRI	
202	Chloromethyl methyl ether	107302	NPRI					NERM			TRI	0.1
203	Chlorophenols										TRI	
204	Chloroprene	126998						NERM			TRI	
205	Chlorothalonil	1897456						NERM			TRI	
206	Chromium	7440473	NPRI		33/50	Ban"	PSL	NERM		Ref	TRI	0.1
207	Chromium compounds		NPRI		33/50						TRI	
208	Chrysene	218019				Ban"	PAH					
209	Cis-2-Butene	590181						NERM				0.1
210	Cobalt	7440484	NPRI					NERM			TRI	
211	Cobalt compounds		NPRI								TRI	
212	Copper	7440508	NPRI			Ban"		NERM			TRI	
213	Copper compounds		NPRI								TRI	
214	Copper sulphate								S<25			
215	Creosote	8001589					PSL	NERM			TRI	0.1
216	Cresol (mixed isomers)	1319773	NPRI					NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
217	Cumene	98828	NPRI					NERM		Ref	TRI	
218	Cumene hydroperoxide	80159	NPRI					NERM			TRI	
219	Cupferron	135206						NERM			TRI	0.1
220	Cyanide compounds				33/50						TRI	
221	Cyanides (ionic) (3)		NPRI									
222	Cyclohexane	110827	NPRI					NERM		Ref	TRI	
223	DDT (+DDD +DDE)	50293				Ban'						
224	Decabromodiphenyl oxide	1163195	NPRI					NERM			TRI	
225	Di-n-octyl Phthalate						PSL					
226	Di-n-octyl phthalate (1) ·	117840	NPRI					NERM			TRI	
227	Diallate	2303164						NERM			TRI	
228	Diaminotoluene (mixed isomers)	25376458						NERM			TRI	0.1
229	Diazomethane	334883						NERM			TRI	
230	Dibenzo(a,c)Anthracene						PAH					
231	Dibenzo(a,h)Anthracene						PAH					
232	Dibenzofuran	132649						NERM			TRI	
233	Dibenzo[a,i]pyrene	189559				Ban"						
234	dibenz[a,h]acridine	226368				Ban"						
235	dibenz[a,j]acridine	224420				Ban"						
236	Dibromotetrafluoroethane (Halon 2402)	124732									TRI	
237	Dibutyl phthalate	84742	NPRI				PSL	NERM			TRI	
238	Dichlorobenzene (mixed isomers)	25321226						NERM			TRI	0.1
239	Dichlorobromomethane	75274					PSL	NERM			TRI	
240	Dichlorodifluoromethane (CFC-12)	75718									TRI	
241	Dichloroethane						PSL					
242	Dichloromethane (Methylene chloride)	75092	NPRI		33/50			NERM			TRI	0.1
243	Dichlorotetrafluoroethane (CFC-114)	76142									TRI	
244	Dichlorvos	62737						NERM			TRI	
245	Dicofol	115322						NERM			TRI	
246	Dieldrin	60571				Ban'						
247	Diepoxybutane	1464535						NERM			TRI	0.1
248	Diethanolamine	111422	NPRI					NERM			TRI	
249	Diethyl phthalate	84662	NPRI					NERM			TRI	0.1
250	Diethyl sulfate	64675	NPRI					NERM			TRI	0.1
251	Dimethyl phthalate	131113	NPRI					NERM			TRI	
252	Dimethyl sulfate	77781	NPRI					NERM			TRI	0.1

	A	B	C	D	E	F	G	H	I	J	K	L
253	Dimethylcarbamyl chloride	79447						NERM			TRI	0.1
254	Dinitrotoluene (mixed isomers)	25321146	NPRI					NERM			TRI	
255	Dioxins											
256	Epichlorohydrin	106898	NPRI					NERM			TRI	0.1
257	Ethane	74840		ECI				NERM				
258	Ethyl acrylate	140885	NPRI					NERM			TRI	0.1
259	Ethyl chloroformate	541413	NPRI					NERM			TRI	
260	Ethylbenzene	100414	NPRI					NERM		Ref	TRI	
261	Ethylene	74851	NPRI					NERM		Ref	TRI	
262	Ethylene glycol	107211	NPRI					NERM			TRI	
263	Ethylene oxide	75218	NPRI					NERM			TRI	0.1
264	Ethylene thiourea	96457	NPRI					NERM			TRI	0.1
265	Ethyleneimine	151564						NERM			TRI	0.1
266	Fluometron	2164172						NERM			TRI	
267	Fluoranthene						PAH					
268	Fluorene						PAH					
269	Formaldehyde	50000	NPRI					NERM	S<2	Ref	TRI	0.1
270	Freon			ECI								
271	Freon 113	76131						NERM			TRI	
272	Furans											
273	g-1,2,3,4,5,6 Hexachlorocyclohexane	58899				Ban'		NERM			TRI	
274	Glycol ethers										TRI	
275	Halon			ECI								
276	Heptachlor	76448						NERM			TRI	
277	Hexachloro-1,3-butadiene	87683				Ban"		NERM			TRI	
278	Hexachlorobenzene	118741				Ban'	PSL	NERM			TRI	0.1
279	Hexachlorocyclopentadiene	77474	NPRI			Ban"		NERM			TRI	
280	Hexachloroethane	67721	NPRI					NERM			TRI	
281	Hexachloronaphthalene	1335871						NERM			TRI	
282	Hexamethylphosphoramide	680319						NERM			TRI	0.1
283	Hydrazine	302012	NPRI					NERM			TRI	0.1
284	Hydrazine sulfate	10034932						NERM			TRI	0.1
285	Hydrochloric acid	7647010	NPRI					NERM	S<10		TRI	
286	Hydrogen cyanide	74908	NPRI		33/50			NERM			TRI	
287	Hydrogen fluoride	7664393	NPRI				PSL	NERM			TRI	
288	Hydroquinone	123319	NPRI					NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
289	Indenol[1,2,3-cd]pyrene	193395				Ban"	PAH					
290	Isobutane	75285						NERM				
291	Isobutyraldehyde	78842	NPRI					NERM			TRI	
292	Isopentane	78784						NERM				
293	Isopropyl alcohol	67630	NPRI					NERM			TRI	0.1
294	Isosafrole	120581	NPRI					NERM			TRI	
295	Lead	7439921	NPRI		33/50	Ban"		NERM		Ref	TRI	0.1
296	Lead compounds		NPRI		33/50						TRI	
297	Lindane	58899				Ban'		NERM			TRI	0.1
298	m-Cresol	108394	NPRI					NERM			TRI	
299	m-Dinitrobenzene	99650						NERM			TRI	
300	m-Xylene	108383	NPRI		33/50		PSL	NERM	S<2	Ref	TRI	
301	Maleic anhydride	108316	NPRI					NERM			TRI	
302	Maneb	12427382						NERM			TRI	
303	Manganese	7439965	NPRI					NERM			TRI	
304	Manganese compounds		NPRI								TRI	
305	Mercury	7439976	NPRI		33/50	Ban'		NERM			TRI	
306	Mercury compounds		NPRI		33/50						TRI	
307	Methane	74828		ECI				NERM				
308	Methanol	67561	NPRI					NERM		Ref	TRI	
309	Methoxychlor	72435						NERM			TRI	
310	Methyl acrylate	96333	NPRI					NERM			TRI	
311	Methyl ethyl ketone	78933	NPRI		33/50			NERM			TRI	
312	Methyl hydrazine	60344						NERM			TRI	
313	Methyl iodide	74884	NPRI					NERM			TRI	0.1
314	Methyl isobutyl ketone	108101	NPRI		33/50			NERM			TRI	
315	Methyl isocyanate	624839						NERM			TRI	
316	Methyl methacrylate	80626	NPRI				PSL	NERM			TRI	
317	Methyl tertbutyl ether (MTBE)	1634044	NPRI				PSL	NERM		Ref	TRI	
318	Methylene bromide	74953						NERM			TRI	
319	Methylenebis (phenylisocyanate) (3)	101688	NPRI					NERM			TRI	
320	Michler's ketone	90948	NPRI					NERM			TRI	0.1
321	Mirex	2385855				Ban'						
322	Molybdenum trioxide	1313275	NPRI					NERM			TRI	
323	Monochlorobenzene						PSL					
324	Monochloropentafluoroethane (CFC-115)	76153									TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
325	Mustard gas	505602						NERM			TRI	0.1
326	N,N-Dimethylaniline	121697						NERM			TRI	
327	N-Butane	106978						NERM				
328	n-Butyl alcohol	71363	NPRI					NERM			TRI	
329	N-Hexane	100543						NERM				
330	N-Nitroso-N-ethylurea	759739						NERM			TRI	0.1
331	N-Nitroso-N-methylurea	684935						NERM			TRI	0.1
332	N-Nitrosodi-n-butylamine	924163						NERM			TRI	0.1
333	N-Nitrosodi-n-propylamine	621647						NERM			TRI	0.1
334	N-Nitrosodiethylamine	55185						NERM			TRI	0.1
335	N-Nitrosodimethylamine	62759						NERM			TRI	0.1
336	N-Nitrosodimethylvinylamine	4549400									TRI	0.1
337	N-Nitrosodiphenylamine	86306	NPRI					NERM			TRI	
338	N-Nitrosomorpholine	59892						NERM			TRI	0.1
339	N-Nitrosonornicotine	16543558						NERM			TRI	0.1
340	N-Nitrosopiperidine	100754						NERM			TRI	0.1
341	N-Pentane	109660						NERM				
342	Naphthalene	91203	NPRI					NERM		Ref	TRI	
343	Nickel	7440020	NPRI		33/50		PSL	NERM		Ref	TRI	0.1
344	Nickel compounds		NPRI		33/50						TRI	
345	Nitric Acid	7697372	NPRI					NERM			TRI	
346	Nitrilotriacetic acid	139139	NPRI					NERM			TRI	0.1
347	Nitrobenzene	98953	NPRI					NERM			TRI	
348	Nitrofen	1836755						NERM			TRI	0.1
349	Nitrogen mustard	51752						NERM			TRI	0.1
350	Nitroglycerin	55630	NPRI					NERM			TRI	
351	NOx	11104931		ECI				NERM				
352	o-Anisidine	90040						NERM			TRI	0.1
353	o-Anisidine hydrochloride	134292						NERM			TRI	0.1
354	o-Cresol	95487	NPRI					NERM			TRI	
355	o-Dichlorobenzene (1)	95501	NPRI					NERM			TRI	
356	o-Dinitrobenzene	528290						NERM			TRI	
357	o-Phenylphenol (1)	90437	NPRI					NERM			TRI	
358	o-Toluidene	95534						NERM			TRI	0.1
359	o-Toluidene hydrochloride	636215						NERM			TRI	0.1
360	o-Xylene	95476	NPRI		33/50		PSL	NERM	S<2	Ref	TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
361	Octachloronaphthalene	2234131						NERM			TRI	
362	Oraganotins						PSL					
363	Osmium tetroxide	20816120						NERM			TRI	
364	p-Anisidine	104949						NERM			TRI	
365	p-Cresidine	120718						NERM			TRI	0.1
366	p-Cresol	106445	NPRI					NERM			TRI	
367	p-Dichlorobenzene (1)	106467	NPRI			Ban'	PSL	NERM			TRI	0.1
368	p-Dinitrobenzene	100254						NERM			TRI	
369	p-Nitrophenol (1)	100027	NPRI					NERM			TRI	
370	p-Nitrosodiphenylamine	156105						NERM			TRI	
371	p-Phenylenediamine	106503	NPRI					NERM			TRI	
372	p-Quinone (1)	106514	NPRI					NERM			TRI	
373	p-Xylene	106423	NPRI		33/50		PS1	NERM	S<2	Ref	TRI	
374	PAHs						PSL					
375	Palustric acid	194535				Ban"						
376	Parathion	56382						NERM			TRI	
377	PBBS										TRI	
378	PCBs	1336363						NERM	S<10		TRI	
379	Pentachlorobenzene	608935				Ban"						
380	Pentachlorobenzene						PSL					
381	Pentachlorophenol	87865				Ban'		NERM	S<10		TRI	
382	Peracetic Acid	79210	NPRI					NERM			TRI	
383	Perylene	198550				Ban'	PAH					
384	Phenanthrene	85018				Ban'	PAH					
385	Phenol	108952	NPRI					NERM	S<2	Ref	TRI	
386	Phosgene	75445	NPRI					NERM			TRI	
387	Phosphoric acid	7664382	NPRI					NERM			TRI	
388	Phosphorous (yellow or white)	7723140	NPRI					NERM	S<25		TRI	
389	Phthalic anhydride	85449	NPRI					NERM			TRI	
390	Picric acid	88891						NERM			TRI	
391	Polychlorinated biphenyls	1336363									TRI	0.1
392	Pottassium chloride								S<10			
393	Propane	74986						NERM				
394	Propane sultone	1120714						NERM			TRI	0.1
395	Propionaldehyde	123386	NPRI					NERM			TRI	
396	Propoxur	114261						NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
397	Propylene (Propene)	115071	NPRI					NERM		Ref	TRI	
398	Propylene oxide	75569	NPRI					NERM			TRI	0.1
399	Propyleneimine	75558						NERM			TRI	0.1
400	Pyrene	129000				Ban"	PAH					
401	Pyridine	110861	NPRI					NERM			TRI	
402	Quinoline	91225	NPRI					NERM			TRI	
403	Quintozene (Pentachloronitrobenzene)	82688						NERM			TRI	
404	Saccharin (2)	81072						NERM			TRI	0.1
405	Safrole	94597	NPRI					NERM			TRI	0.1
406	sec-Butyl alcohol	78922	NPRI					NERM			TRI	
407	Selenium	7782492	NPRI					NERM			TRI	
408	Selenium compounds		NPRI								TRI	
409	Silver	7440224	NPRI			Ban"		NERM			TRI	
410	Silver compounds		NPRI								TRI	
411	Sodium Chlorate								S<25			
412	Sodium Chloride								S<25			
413	Sodium cyanide								S<10			
414	Sodium hydroxide								S<25			
415	SOx	12624327		ECI				NERM				
416	Styrene	100425	NPRI			Ban"	PSL	NERM	S<10		TRI	0.1
417	Styrene oxide	96093	NPRI					NERM			TRI	0.1
418	Sulphuric acid	7664939	NPRI					NERM	S<1	Ref	TRI	
419	Terephthalic acid	100210									TRI	
420	tert-Butyl alcohol	75650	NPRI					NERM			TRI	
421	Tetrachlorobenzene						PSL					
422	Tetrachloroethane						PSL					
423	Tetrachloroethylene	127184	NPRI		33/50		PSL	NERM			TRI	0.1
424	Tetrachlorvinphos	961115						NERM			TRI	
425	Tetrachologuaiacol	2539175				Ban"						
426	Tetraethyllead	78002				Ban"			S<10			
427	Thallium	7440280						NERM			TRI	
428	Thallium compounds										TRI	
429	Thioacetamide	62555						NERM			TRI	0.1
430	Thiourea	62566	NPRI			Ban"		NERM			TRI	0.1
431	Thorium dioxide	1314201	NPRI					NERM			TRI	
432	Titanium tetrachloride	7550450	NPRI					NERM			TRI	

	A	B	C	D	E	F	G	H	I	J	K	L
433	Toluene	108883	NPRI		33/50		PSL	NERM	S<2	Ref	TRI	
434	Toluene-2,4-diisocyanate	584849	NPRI					NERM			TRI	0.1
435	Toluene-2,6-diisocyanate	91087	NPRI					NERM			TRI	0.1
436	Toluenediisocyanate (mixed isomers)	26471625	NPRI					NERM			TRI	0.1
437	Toxaphene	8001352				Ban'		NERM			TRI	0.1
438	Triaziquone	68768						NERM			TRI	0.1
439	Tributyl tin	688733				Ban'						
440	Trich-oroethylene	79016	NPRI		33/50			NERM			TRI	
441	Trichlorfon	52686						NERM			TRI	
442	Trichlorobenzene						PSL					
443	Trichloroethane						PSL					
444	Trichloroethylene						PSL					
445	Trichlorofluoromethane (CFC-11)	75694									TRI	
446	Trifluralin	1582098						NERM			TRI	
447	Triphenyl phosphate	115866				Ban"						
448	Triphenylene						PAH					
449	Tris(2,3-dibromopropyl)phosphate	126727						NERM			TRI	0.1
450	Trixylyl phosphate	25155231				Ban"						
451	Uranium	7440611				Ban"						
452	Urethane	51796						NERM			TRI	0.1
453	Vanadium (fume or dust)	7440622	NPRI					NERM			TRI	
454	Vinyl acetate	108054	NPRI					NERM			TRI	
455	Vinyl bromide	593602						NERM			TRI	0.1
456	Vinyl chloride	75014	NPRI					NERM			TRI	0.1
457	Vinylidene chloride	75354	NPRI					NERM			TRI	
458	Xylene (mixed isomers)	1330207	NPRI					NERM			TRI	
459	Zinc (fume or dust)	7440666	NPRI			Ban"		NERM			TRI	
460	Zinc compounds		NPRI								TRI	
461	Zinc sulphate								S<25			
462	Zineb	12122677						NERM			TRI	
463												
464	June/93 NPRI Revisions:											
465	(1) name change, same CASRN											
466	(2) deleted											
467	(3) additions											
468												

ACCO

CUSTOMIZER D-RING - 1.5"

WHITE	13415	BLANC
BLACK	13425	NOIR
RED	13435	ROUGE
GREY	13445	GRIS
BLUE	13455	BLEU

ACCO CANADA INC.
WILLOWDALE, ONTARIO